

Chapter Six: Specific Issues Relating to Oil and Gas Exploration, Development, Production and Transportation

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A. Geophysical Hazards

The primary geophysical hazards within the sale area include earthquakes, faulting, ice zonation, shore-ice movement, permafrost and frozen-ground phenomena, waves, coastal erosion, offshore currents, seasonal flooding, strudel scour, overpressured and unstable sediments, and shallow gas deposits and hydrates. These geohazards could impose constraints to exploration, production, and transportation activities associated with possible petroleum development, and should be considered prior to any siting, design and construction of any facilities.

1. Faults and Earthquakes

Surface faults¹ have been mapped throughout the Central Beaufort including high-angle faults, basement-involved² normal faults, listric growth faults³, and north-dipping gravity faults⁴. Locally, two or more types may occur in close proximity to each other.

High-angle faults occur along the Barrow Arch extending into Harrison Bay. Along the Barrow Arch they are related to the basement tectonics of the Arctic Platform⁵ while in Harrison Bay, they offset the Tertiary and older units (See Table 6.1). There has been little evidence of any Quaternary movement with no evidence of displacement in the Pleistocene or Holocene sediments and there has been no recent seismicity associated with these faults. Thus, differential movement along these faults seems to have ended prior to the beginning of the Quaternary Period (Craig and Thrasher, 1982).

A number of shallow faults have been mapped north of the Arctic Platform. Included in these faults are the upper extensions of detached listric growth faults that exist deep in the Brookian section. These faults have been mapped in the greatest detail in the Camden Bay area where some of these faults may have been reactivated in the late Cenozoic and can have several tens of meters of offset. Shallow faults have also been mapped beneath the outer shelf, west of Cape Halkett, and are reported to show from 3 to 10 m of Quaternary offset (Grantz and others, 1983).

In contrast to the rest of the Beaufort shelf, the Camden Bay area is still seismically active. This region is located at the northern end of a north-northeast trending band of seismicity that extends north from east-central Alaska (Biswas and Gedney, 1979). Since monitoring began in 1978, a large number of earthquakes, ranging from one to over five on the Richter Scale, have been recorded in this area, with the

¹ A fault is a surface or zone of rock fracture along which there has been displacement, from a few centimeters to a few kilometers in scale (American Geological Institute, Glossary of Geology, 1973).

² The term "basement" refers to the surface beneath which sedimentary rocks are not found (Encyclopedic Dictionary of Exploration Geophysics, 1991).

³ A "listric" surface is a curvilinear, usually concave-upward surface of fracture that curves, at first gently and then more steeply, from a horizontal position. Listric surfaces form wedge-shaped masses, appearing to be thrust against or along each other (American Geological Institute, Glossary of Geology, 1973).

⁴ A gravity fault is a normal fault in which movement is downward.

⁵ A "platform" refers to that part of a continent which is covered by a flat-lying or gently tilted strata, mainly sedimentary, which are underlain at varying depth by a basement of rocks that were consolidated during earlier deformations (American Geological Institute, Glossary of Geology, 1973).

majority of events clustering along the axis of the Camden anticline⁶. The largest earthquake recorded in the area was a magnitude 5.3 event located 30 km north of Barter Island in 1968. In this region, the Tertiary and Quaternary units dip away from and are truncated at the top of the Camden anticline, indicating that it has been growing in recent geologic time. The faults in this region trend northwest-southeast, parallel to the hinge line⁷, and as they approach and intersect the axis of the Camden anticline, they offset progressively younger units. This suggests that these faults are older hinge line-related structures that were reactivated in late Tertiary and Quaternary by the uplift of the Camden anticline.

Table 6.1 Geologic Time and Formations

Eras	Periods	Epochs	Began Approximate Number of Years Ago
Cenozoic	Quaternary	Holocene (Recent)	10,000
		Pleistocene (Glacial)	1 million
	Tertiary	Pliocene	7 million
		Miocene	25 million
		Oligocene	40 million
		Eocene	60 million
		Paleocene	68-70 million
Mesozoic	Cretaceous	Upper & Lower	135 million
	Jurassic		180 million
	Triassic		225 million
Paleozoic	Permian		270 million
	Pennsylvanian		325 million
	Mississippian		350 million
	Devonian		400 million
	Silurian		440 million
	Ordovician		500 million
	Cambrian		600 million

Source: Webster's Ninth New Collegiate Dictionary, 1991:512 and AEIDC, 1975:37

North of the sale area, on the outer Beaufort shelf and upper slope are gravity faults that are related to large rotational slump blocks⁸ (Grantz and Dinter, 1980). South of these slumps, which bound the seaward edge of the Beaufort Ramp, these faults have surface offsets ranging from 15 m to as high as 70 m (Grantz and others, 1982b). Grantz and others (1982b) have inferred that these faults have been active in recent geologic time based on the age of the faults and therefore pose a hazard to bottom-founded structures in this area. Large-scale gravity slumping of the blocks here could be triggered by shallow-focus earthquakes centered in Camden Bay or in the Brooks Range.

Throughout the region (Figure 6.1) approximately 45 earthquakes have been recorded between January 1968 and December 1995. Most of the seismicity in the region is shallow (less than 20 miles deep), indicating near-surface faulting.

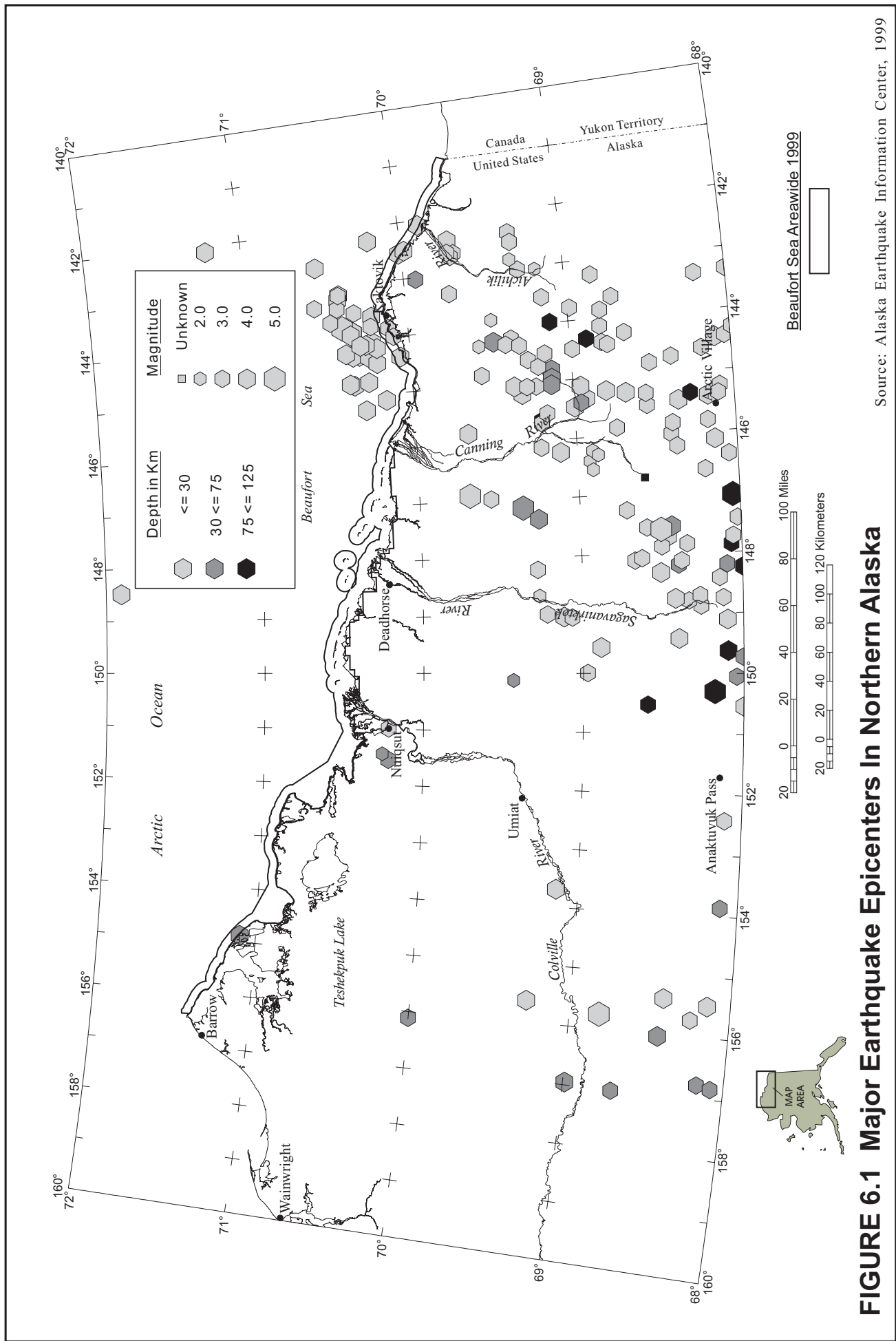
Algermissen and others (1991) estimate a 10 percent probability of exceeding 0.03 g⁹ earthquake-generated horizontal acceleration in bedrock during a 50-year period in this area. For comparison, ground acceleration in Anchorage during the great 1964 earthquake was estimated at 0.16 g. In areas throughout the sale area underlain by thick, soft sediments, the ground accelerations are likely to be higher than in bedrock

⁶ An "anticline" is a fold, the core of which contains the stratigraphically older rocks; it is convex upward. The opposite is called a syncline (American Geological Institute, Glossary of Geology, 1973).

⁷ Generally, a hinge line refers to a line or boundary between a stable region and a region undergoing upward or downward movement (American Geological Institute, Glossary of Geology, 1973).

⁸ A "slump block" is the mass of material torn away as a coherent unit during a block slump. The rotation refers to the apparent fault-block displacement in which the blocks have rotated relative to one another, so that alignment of formerly parallel features is disturbed (American Geological Institute, Glossary of Geology, 1973).

⁹ Gravitational acceleration. One g equals an acceleration rate of 32 feet per second per second.



due to amplification. However, thick localized permafrost may cause the earthquake response of sediments to be more like bedrock, which would limit amplification effects and would also tend to prevent earthquake-induced ground failure, such as liquefaction.

It is standard industry practice that facility siting, design, and construction be preceded by site-specific, high-resolution, shallow seismic surveys that reveal the location of potentially hazardous geologic faults. These surveys are required by the state prior to locating a drilling rig. Facility planners are encouraged to consult with the American Petroleum Institute's publication, *Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions, Second Edition, December 1, 1995.* This document contains considerations that are unique for planning, designing, and constructing Arctic systems.

The entire sale area lies within seismic zone 1 of the Uniform Building Code (on a scale of 0 to 4, where 4 represents the highest earthquake hazard), and earthquake potential is low. Regardless, all structures in the sale area should be built to meet or exceed the Uniform Building Code requirements for zone 1 (Combellick, 1994).

2. Ice Zonation

The Beaufort Shelf is covered with ice most of the year, with a typical ice-free period during August and September only. The sea ice first forms in late September to early October and becomes continuous nearshore by mid-October. This ice will remain through the winter and start breaking up in July. It is not until early August that the nearshore region is largely ice free (Barry, 1979). During the winter months, the offshore ice can be divided into three main zones: the landfast zone, the shear zone (or Stamukhi zone), and the pack ice zone (Reimnitz and Barnes, 1974). The landfast ice forms along the shore and develops seaward in the early fall. Small movements of this ice can be related to storm fronts which cause narrow leads and rubble fields in this zone. In late winter, the fast ice can extend out to the 25-meter to 30-meter isobath.

The shear zone, or Stamukhi zone, is located between the landfast ice and the pack ice zone. It is a transition zone between the relatively stationary landfast ice and the highly mobile pack ice. Fragments of seasonal ice, multi-year ice and ice ridges up to tens of meters high exist in this zone. It is here where there is an intense interaction between the ice and the seabed, where the ice can gouge the seabed to depths of several meters (Reimnitz and Barnes, 1974).

The pack ice zone, seaward of the Stamukhi zone, is the shoreward edge of the permanent polar ice cap. It consists of multi-year ice, ice ridges, and ice island fragments that migrate westward in response to the clockwise circumpolar gyre (Reimnitz and Barnes, 1974). During the summer, the ice can move up to 20 km/day. During the summer, the pack ice usually occurs tens to hundreds of kilometers offshore and so will not affect the sale area.

The National Ice Center currently monitors, analyzes, publishes current conditions and forecasts the ice conditions along the Beaufort coastline. They use visual, infrared, passive microwave and Synthetic Aperture Radar imagery, as well as ship reports and aerial reconnaissance to produce these data (Andrews and Benner, 1996). Since the central Beaufort is characterized by significant, rapid changes in ice conditions, mathematical modeling of the evolution of the sea ice cover has been developed to help predict the ice conditions more precisely. By using these data it is possible to determine different ice characteristics such as: ice concentration, thickness distribution, edge configuration, drift velocity, zones of divergence and compacting, distribution of ice floe sizes, and their strength and motion (Appel, 1996).

A massive iceberg or ice island could present a danger to structures beyond state territorial waters where depths are great enough to allow for large ice masses to approach the coastal zone. Ice islands are produced by the break-up of portions of the Ellesmere Ice Shelf and are the tabular icebergs of the Arctic Ocean. They are usually 40 to 50 m thick with lateral dimensions that range from tens of meters to tens of kilometers. If one became imbedded in the arctic ice pack and hit an offshore production facility, the facility would likely be destroyed. This geophysical hazard poses no threat to exploration or development in the sale area because of the shallow water depth.

Sea ice poses a potential hazard to offshore and coastal structures if they are not properly designed; a concrete island drilling structure could be pushed off location, ice could override a fixed structure, or a marine pipeline could be damaged where it comes ashore. Facilities exposed to the potential risks of each sea ice zone must be designed to accommodate ice forces.

Structures exposed to ice forces are fortified with sheet piling, concrete armor, and large bags filled with dense material placed in the path of moving sheets of ice. Existing steel and concrete island drilling structures placed in multi-year ice are durable and can accommodate closely spaced well designs. Gravel islands are designed with 10:1 slopes above sea level, and 5:1 slopes as deep as 20 ft. below sea level. They are also constructed with a sheetpile retaining ring. Slopes are protected by fabricated blocks and filter fabric anchored to sheetpile.

All offshore structures in state waters must be bottom-founded (NSBMC 19.70.040(A)), which considerably reduces the risk of damage to oil and gas facilities from sea ice movements. Exploratory drilling in winter is conducted with ice pads frozen to the sea bottom. This method of exploratory drilling is expected to be used throughout the sale area. Most of the sale area, and all of the region shoreward of the barrier islands is seasonally covered by stable fast ice, generally ridge free. Thus, the risk of damage to facilities is reasonably predictable, and can be accounted for in the design. Sea ice remains stable throughout the drilling period (November to April). However, severe winter storms, such as one in November 1978, have been known to break-up land-fast ice and create large pressure ridges (Thomas, D. R., 1984:447). Therefore, contingency plans must be in place to demobilize a drill rig in a short period of time if weather becomes adverse.

All operations must comply with NSB municipal Code offshore development policies (NSBMC 19.70.040) which include measures to prevent an uncontrolled release of oil. Drilling below threshold depth must be conducted during winter (November 1 through April 15) and be completed as early in this period as practicable (NSBMC 19.70.040(C)) to minimize the risk of an oil spill caused by ice movements.

NSB municipal code requires plans for offshore drilling activities to include a relief well drilling plan and an emergency countermeasures plan. The emergency countermeasures plan must identify the steps that will be taken to protect human life and minimize environmental damage in the event of loss of a drilling rig; ice override; or loss or disablement of support craft or other transportation systems (NSBMC 19.70.050(I)(6)).

“Offshore structures must be able to withstand geophysical hazards and forces which may occur while at the drill site. Design criteria must be based on actual measurements or conservative estimates of geophysical forces. In addition, structures must have monitoring programs and safety systems capable of securing wells in case unexpected geophysical hazards or forces are encountered.” (NSBMC 19.70.050(I)(2) and NSBCMP Policy 2.4.4(b)).

3. Ice Gouging

Ice gouging is primarily active at mid-shelf and inner-shelf water depths. On the mid-shelf, ice ridges can scour the seafloor to depths of several meters. Reimnitz and Barnes (1974) found gouges as deep as 5.5 m, with ridges up to 2.7 m high just west of the sale area in Smith Bay. Barnes (1981) has measured the average ice gouge on the Beaufort shelf at 50 cm deep, ridges 40 cm high, and 7.5 m wide. Ice gouges have been found to range between 1 and 10 m of relief.

Although ice gouges can be found across the entire shelf, they are concentrated in the Stamukhi zone, generally between the 18-meter and 30-meter isobaths. The shoals and islands often show little or no evidence of ice gouging on their down-drift side with the highest intensity of gouging occurring on the up-drift side (Reimnitz and others, 1982). In the Prudhoe Bay area, there is very little ice gouging due to the location of the barrier islands, while in Harrison Bay, where there are no barrier islands, high-intensity ice gouging occurs.

At water depths less than 18 m, inshore of the Stamukhi zone, the ice gouging is much less severe. In this region, any ice gouges which form are rapidly buried by sand waves or sediment sheets. Since the

nearshore sediments tend to be coarser grained than those farther offshore, any ice gouges in this region will degrade more rapidly than in the more cohesive, fine-grained sediments farther offshore (Barnes and Reimnitz, 1979).

As the water depth increases offshore of the Stamukhi zone, the number of ice keels large enough to reach the bottom decreases, although ice gouges have been reported in water as deep as 58 m. Closer to the outer shelf edge, strong geostrophic currents exist which smooth the older ice gouges by eroding and filling them (Reimnitz and others, 1982).

In general, the ice gouges throughout the central Beaufort shelf are oriented east-west, although they vary considerably more on the inner shelf where the shoals and other bottom features can deflect the ice. This east-west orientation reflects the directions of the surface current as well as the prevailing wind throughout the region.

Ice gouging poses little hazard to offshore exploration or production structures. Ice gouging does pose a significant risk to oil and gas transportation, particularly sub-sea pipelines. Such pipelines are trenched deep beneath the deepest predicted scour depth, and covered with protective material. This could constitute backfill of in-situ or other material. Protective armament at all locations is not necessarily warranted, but could be a site-specific requirement.

4. Ice Movement

Ice movement (ice ride-up and override) can result from wind, current, waves or temperature changes. Continuous, large scale ice movements are caused by major current systems (e.g., the Beaufort Gyre in the Arctic Ocean), tidal currents, or geostrophic winds. Major contributions to local, short term movements are wind, wave, and current action during storms. Ice movements during a single ice season create zones of land fast and pack ice. Zone boundaries are not static, but change with seasonal ice growth and movement. Ice movements at a given site may have a predominant direction due to geography and environmental conditions (API, 1995).

Throughout the Beaufort Sea, both ice ride-up and ice override can transport and erode significant amounts of sediment. Ice ride-up is the process whereby ice blocks are forced onshore by strong wind or currents and push the sediment from the coast into the ridges farther inland. It is most important on the outer barrier islands where ice ride-up ridges up to 2.5 m high, extending 100 m inshore from the beach have been identified (Hopkins and Hartz, 1978). Over most of the Arctic coast, ice ride-up rubble is found at least 20 m inland with boulders in excess of 1.5 m in diameter (Kovacs, 1984). A number of accounts of ice ride-up events have been documented where man-made structures have been damaged along the Beaufort coast. In January of 1984, ice over-topped the Kadluck, an 8 m-high caisson-retained drilling island located in Mackenzie Bay (Kovacs, 1984). Ice ride-up has the potential to alter shorelines and nearshore bathymetry, which in the longer term may pose a threat to nearshore facilities with increased erosion.

Ice override can occur offshore or onshore. Ice can override itself, rafted ice, or can override the coastline and ride-up onto a shore. Ice override onshore will add an additional dead load (ice on top of a buried pipeline) to a buried pipeline in the transition area from offshore to onshore beginning where the ice contacts the sea floor. This dead load (weight of the ice) along with the force being exerted by the ice should be considered in pipeline design (Rice, 1999).

5. Sub-Sea Permafrost

Numerous refraction, borehole and conductivity surveys indicate that permafrost is widespread beneath the Beaufort inner shelf. A number of seismic refraction surveys have been run by Rogers and Morack (1981), Neave and Sellmann (1983) and Morack and others (1983). Additional data have been obtained from boreholes (Harding-Lawson, 1979) and thermal probes (Hopkins and Hartz, 1978b; Rogers and Morack, 1981; Harrison and Osterkamp, 1981). The depth to the surface of the subsea permafrost is highly

variable, which reflects the varying degrees of ice-bonding prior to the Holocene marine transgression as well as the degree of subsequent thawing due to the advection of saline groundwater.

Historically, the Beaufort shelf has been subaerially exposed to the Arctic climate during several Pleistocene lowstands of sea level followed by subsequent highstands (Wang and others, 1982). During these episodes, the permafrost formed to depths of several hundred meters during the lowstands followed by highstand periods where it was partially melted by saline advection from the seawater into the underlying sediment and by geothermal heating. In a study by Harding-Lawson (1979), boreholes encountered ice at depths shallower than 9 m to over 30 m over a distance of less than 12 km. It is estimated that well-bonded permafrost (permafrost having a greater ice crystal matrix) will form in a subaerial Arctic environment in only 40 to 50 years (Hopkins and Hartz, 1978a).

Permafrost can therefore be expected to occur in the core of some of the barrier islands and artificial islands. On Reindeer Island, the Humble Oil C-1 well encountered two layers of permafrost at depths of 0 to 18.9 m and 91 to 128 m. The shallower layer may have formed under modern Arctic conditions while the deeper layer was probably formed during the Pleistocene (Sellmann and Chamberlain, 1979).

Sub-sea permafrost can pose a hazard to bottom-founded drilling structures via thaw and subsidence, if its presence is not considered in design and construction. Geophysical data acquired prior to development can reveal the presence and distribution of sub-sea permafrost. Structures placed on top of permafrost must be designed to prevent heat loss into the substrate. The presence of sub-sea permafrost is a major consideration in the siting and design of sub-sea pipelines. The effect of heat loss to the surrounding substrate can be minimized by trenching and backfilling along the pipeline corridor, and by insulating the pipe. Chilling the oil or gas in pipelines may also reduce the potential effects posed by the presence of sub-sea permafrost.

6. On-Shore Permafrost, Frozen Ground and Thermokarst

Permafrost exists throughout most of the onshore portion of the sale area and is, for the most part, a relict¹⁰ feature overlain by a layer of unconsolidated sediment. The thickness has been measured from numerous onshore wells indicating that it thins from east to west. East of Oliktok Point, it has been measured to be 500 m thick, whereas west of the Colville River it has been measured to be 300 to 400 m thick (Osterkamp and Payne, 1981). The depth of seasonal thaw is generally less than 1 m below the surface and 2 m beneath most active stream channels and is dependent site-specific hydrological and geotechnical water crossing conditions. Borings for the Colville River, for example, show it remains thawed year-round. The ice content varies throughout the region from segregated ice to massive ice in the form of wedges and pingos, and is the highest in the fine-grained, organic-rich deposits and the lowest in the coarse granular deposits and bedrock (Collett and others, 1989).

Ground settlement, due to thawing, occurs whenever a heated structure is placed on ground underlain by shallow, ice-rich permafrost, and proper engineering measures are not taken to adequately support the structure and prevent the structure's heat from melting the ground ice. In addition, the seasonal freeze-thaw processes will cause frost jacking of nonheated structures placed on any frost-susceptible soils unless the structures are firmly anchored into the frozen ground with pilings or supported by non-frost-susceptible fill (Combellick, 1994). The frost susceptibility of the ground is highest in fine-grained alluvium, colluvium, thaw-lake deposits, and coastal-plain silts and sands; moderate in alluvial-fan deposits and till; and lowest in coarse-grained flood-plain deposits, alluvial terrace deposits and gravely bedrock (Carter and others, 1986; Ferrians, 1971; Yeend, 1973a, b). Thermokarst is caused by the disturbance or removal of vegetation resulting in local melting of ground ice. This causes uneven topography in the form of mounds and sink holes. Even small disturbances such as a vehicle driven across the tundra can create thermokarst features. This can be mitigated through seasonal and area restrictions on vehicles.

¹⁰ A "relict" feature pertains to a mineral, structure, or feature of a rock that represents those of an earlier rock and which persist in spite of processes tending to destroy it (American Geological Institute, Glossary of Geology, 1973).

Frozen ground, permafrost, and thermokarst problems can be mitigated through proper siting, design, and construction, as has been demonstrated at Prudhoe Bay. Structures, such as drill rigs and permanent processing facilities, should be designed to prevent heat loss into the substrate. Pipelines can be trenched, back-filled, and chilled (if buried) or elevated to prevent undesirable thawing of permafrost.

7. Waves and Coastal Erosion

Wave heights along the Beaufort coastline are low throughout most of the year because of the short fetch resulting from the pervasive ice cover. However, in the fall open-water season, a considerable fetch can develop both seaward and shoreward of the barrier islands. During this time, storm waves can reach up to 7 to 9 m when the fetch is equal to 800 km and can become effective erosive agents both onshore and along the exposed faces of the barrier islands (Appel, 1996). Also, wind-induced storm surges can force the ice and water onshore and can raise sea level as much as 3 m, with an additional meter added to this due to low atmospheric pressures associated with the storms (Barnes and Reimnitz, 1974). During the most extreme surges, the coastal islands can become completely flooded, and major changes in the size and shape of these islands can occur during a very short time period (Reimnitz and Maurer, 1978b).

Even with the short open-water season along the Beaufort coastline, the wave action, in combination with the melting of coastal permafrost, can cause dramatic rates of coastal erosion. Average rates of erosion across the Beaufort coastline range from 1.5 to 4.7 m per year, with short term erosion rates of 30 m per year. In one case, near Oliktok Point, the coastline eroded 11 m during one two-week period (Hopkins and Hartz, 1978a).

The highest rates of erosion occur along the coastal promontories where the bluffs are composed of fine-grained sediments and ice lenses. In some areas, beaches have been formed from the gravel eroded from bluffs composed of coarse-grained deposits and act to partially isolate those bluffs from wave action. In other areas, where the bluffs are composed of fine sediment, the sand eroded from the bluffs do not form protective beaches, allowing the bluffs to erode more rapidly. In the Harrison Bay area, where for example, the bluffs are composed primarily of coarser grained sediments, the average retreat rates are between 1.5 to 2.5 m per year (Craig and others, 1985).

The only prograding (advancing) shoreline areas along the Beaufort coastline occur off the deltas of major rivers. In those areas, the rate of progradation is very slow, such as the Colville River, which averages 0.4 m per year (Reimnitz and others, 1985).

Bank erosion along the rivers in the region is produced through similar processes, where the sediment cohesiveness is a major factor in determining the river bank erodibility. In this case, the higher erosion rates occur along the braided channels, which usually develop in areas composed of noncohesive sediment (Scott, 1978). In a study along the Sagavanirktok River, aerial photographs showed a maximum erosion rate of 4.5 m per year during a 20-year period. In this area, most of the erosion appeared to occur in small increments during breakup flooding and was concentrated in specific areas where conditions were favorable for thermo-erosional niching (Combellick, 1994).

Erosion rates, sediment grain size and cohesiveness, river bank stability, and nearshore bathymetry must all be considered in determining facility siting, design, construction, and operation. They must also be considered in determining the optimum oil and gas transportation mode. Structural failure can be avoided by proper facility set-backs from coasts and river banks. Mitigation Measure 24 prohibits the siting of permanent facilities, other than road and pipeline crossings, within one-half mile of the banks of the main channel of the Colville, Canning and Sagavanirktok, Kavik, Shaviovik, Kadleroshilik, Echooka, Ivishak, Kuparuk, Toolik, Anaktuvuk, and Chandler Rivers. Docks and road or pipeline crossings can be fortified with concrete armor, and the placing of retainer blocks and concrete-filled bags in areas subject to high erosion rates, such as at the Endicott causeway breaches. Mitigation Measure 11 prohibits the siting of causeways or docks in river mouths or deltas.

8. Coastal Currents

Marine currents along the central Beaufort shelf are primarily wind driven and are strongly regulated by the presence or absence of ice. Sediment is transported by these currents along the barrier islands and the coastal promontories, although, due to the short open-water season, the annual rate of longshore sediment transport is relatively low. The currents along the inner shelf generally flow to the west in response to the prevailing northeast wind, with current reversals occurring close to shore during storms. Further from the shoreline, on the open shelf, the currents average between 7 and 10 cm/sec (Matthews, 1981). During storms, east-flowing currents have been measured with velocities of up to 95 cm/sec, although typical storm current velocities are an order of magnitude lower (Kozo, 1981). Under the ice, in the winter, the currents are usually less than 2 cm/sec, although some currents have been measured at up to 25 cm/sec in areas around grounded ice blocks (Matthews, 1981).

Geostrophic currents can occur north of the sale area on the outer shelf, flowing parallel to the shelf-slope break. These currents have been measured at up to 50 cm/sec and can occur in both easterly and westerly directions (Craig and others, 1985). Since the tidal range on the central Beaufort shelf is small, approximately 15 to 30 cm, the tidal currents exert only minor influences on the sedimentary regime (Matthews, 1981). When the water flow on the shelf is restricted by bottom-fast ice, these currents can act as important scouring agents (Reimnitz and Kempema, 1982b).

Offshore structures are designed to withstand variable marine currents in the Beaufort Sea. Additionally, all drilling structures are bottom-founded and fortified to counteract any current-induced scouring. Artificial or natural gravel islands must be fortified and built to withstand coastal currents as well as the forces of moving sea-ice for the life span of the producing field. To this end, they may require periodic maintenance in response to heavy storms.

9. Seasonal Flooding

Floods occur annually along most of the rivers and many of the adjacent low terraces due to the seasonal snow melt and ice jamming (Rawlinson, 1993). As the weather warms up, during the spring runoff, the river flood waters inundate the landfast sea ice. At this time of year, large areas of the fast ice are covered with water to depths of up to 1.5 m, as far as 30 km from the river mouths. When the flood water reaches openings in the ice, it rushes through with enough force to scour the bottom to depths of several meters by the process called strudel scouring (Reimnitz and others, 1974).

In addition to the seasonal flooding, many of the rivers along the coast are subject to seasonal icing prior to the spring thaw. This is due to the overflow of the stream or ground water under pressure, and in the areas of repeated overflow, the residual ice sheets often become thick enough to extend beyond the flood-plain margin. These large overflows and residual ice sheets have been documented on the Sagavanirktok, Shaviovik, Kavik, and Canning Rivers (Dean, 1984; Combellick, 1994).

Storm surges along the Beaufort coast frequently occur in the summer and fall. Sea level increases of 1 to 3 m have been observed, with the largest increases occurring on the westward-facing shores. Storm surges can also occur from December through February, although the sea level elevation changes are generally less than in summer and fall. Decreases in the elevation of the sea level can occur and occur more frequently during the winter months (MMS, 1995).

Seasonal flooding of lowlands and river channels is extensive along major rivers that drain into the sale area. Thus, measures must be taken prior to facility construction and field development to prevent losses and environmental damage. Pre-development planning should include hydrologic and hydraulic surveys of spring break-up activity as well as flood-frequency analyses. Data should be collected on water levels, ice floe direction and thickness, discharge volume and velocity, and suspended and bedload sediment measurements for analysis. Also, historical flooding observations should be incorporated into a geophysical hazard risk assessment. All inactive channels of a river must be analyzed for their potential for reflooding. Containment dikes and berms may be necessary to reduce the risk of flood waters that may undermine facility integrity.

10. Strudel Scour

Strudel scour is a process where freshwater runoff from rivers in the spring flows on top of the shorefast ice, and eventually drains into the sea through open spaces. The force of this water forms a downward vortex which scours holes in the sea bottom. Along the Beaufort shelf, strudel scour craters have formed up to 6 m deep and 20 m across as mapped by shallow bathymetric surveys and scuba diving observations (Reimnitz and others, 1974). The more sheltered coastal areas and bays adjacent to the major rivers, such as the Colville, Sagavanirktok, and the Canning, are particularly susceptible to this type of scouring. In these areas, the deltas can be totally reworked by strudel scouring in several thousand years (Reimnitz and Kempema, 1982a). The areas of strudel scour that have been measured along the Beaufort shelf are shown in Figure 6.2.

11. Overpressured Sediments

Strudel scouring has the potential to undermine substrate upon which a nearshore structure is placed, such as an artificial island placed in a river mouth or delta. It is unlikely that such a structure would be permitted as it may violate NSBCMP Best Effort Policies regarding alteration of shoreline dynamics by mining, and placing of structures subject to a 50-year recurrence level (NSBCMP 2.4.5(i) and (j)).

Along the central Beaufort region, extremely high pore pressures can be expected to be found where Cenozoic strata (sedimentary layers) are very thick, such as in the Kaktovik, Camden, and Nuwuk Basins. Onshore, in the Camden Basin, high pore pressures have been measured in both the Tertiary and Cretaceous formations where the burial depths of the Tertiary strata exceeded 3 km (Craig and others, 1985).

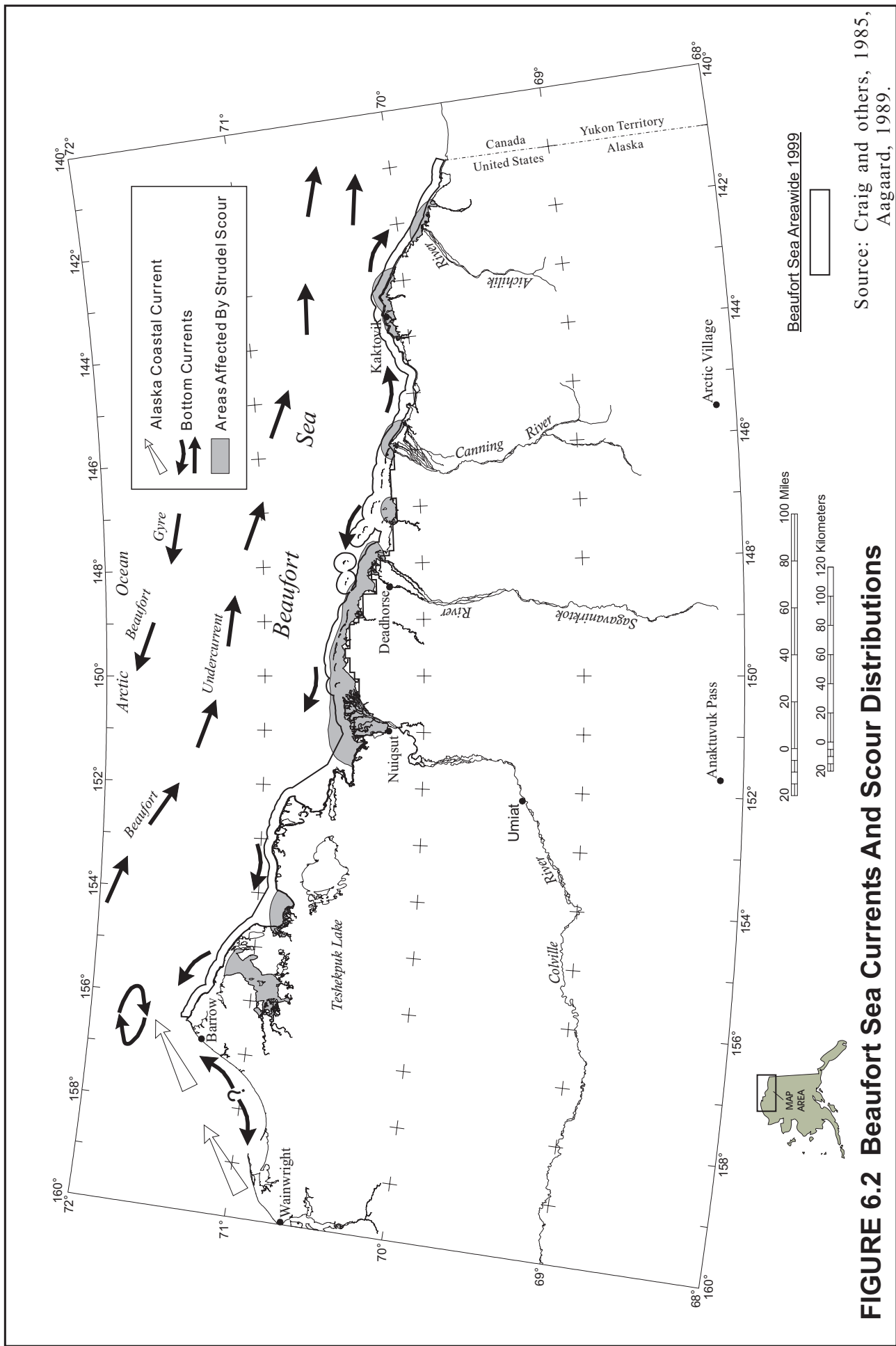
In the Point Thomson area, the pore pressure gradients were measured as high as 0.8 pounds per square inch per foot (psi/ft) in sediments at burial depths of 4 km. In this area a pore pressure gradient of 0.433 psi/ft is considered normal (Hawkings and others, 1976). High pore pressures have also been measured throughout the Cenozoic strata of the Mackenzie Delta in the Canadian Beaufort. Here, the pore-pressure gradients were measured as high as 0.76 psi/ft and have been observed at depths as shallow as 1.9 km (Hawkings and others, 1976).

Drilling mud in the well-bore is mixed to a specific density that will equal or slightly exceed the pressure in the formation. When formation pressures exceed the weight of the drill mud in the well-bore, the result can be a kick¹¹ or blow-out. Thus, encountering over-pressured sediments while drilling can result in a blow-out or uncontrolled flow. The risk of a blow-out is reduced by identifying locations of overpressured sediments via seismic data analysis, and then adjusting the mud mixture accordingly as the well is drilled. If a kick occurs, secondary well control methods are employed. The well is shut-in using the blow-out prevention (BOP) equipment installed on the wellhead after surface casing is set. The BOP equipment closes off and contains fluid pressures in the annulus and the drillpipe. BOP equipment is required for all wells and surface and sub-surface safety valves are required to automatically shut-off flow to the surface.

12. Unstable Sediments

The distribution of modern sediments on the central Beaufort is greatly affected by the density of ice gouging, the wave and current activity, and the composition of the sediment delivered from the rivers and the coastal bluffs (see Figure 6.3). The ability of these sediments to support the weight of bottom-founded structures and to resist sliding when sea ice interacts with the structure can vary greatly. The sediments consist predominantly of coarser grained material (sand and gravel sized particles) in the nearshore areas, near the offshore barrier islands and on shoals and along the shelf break. Further offshore, at depths of 20 m and greater, the sediments consist primarily of mud (clay and silt sized particles) (Craig and others, 1985).

¹¹ A kick is a condition where the formation fluid pressure (pressure exerted by fluids in a formation) exceeds the hydrostatic pressure (pressure exerted by mud in the borehole) resulting in a 'kick'; formation fluids enter the borehole.



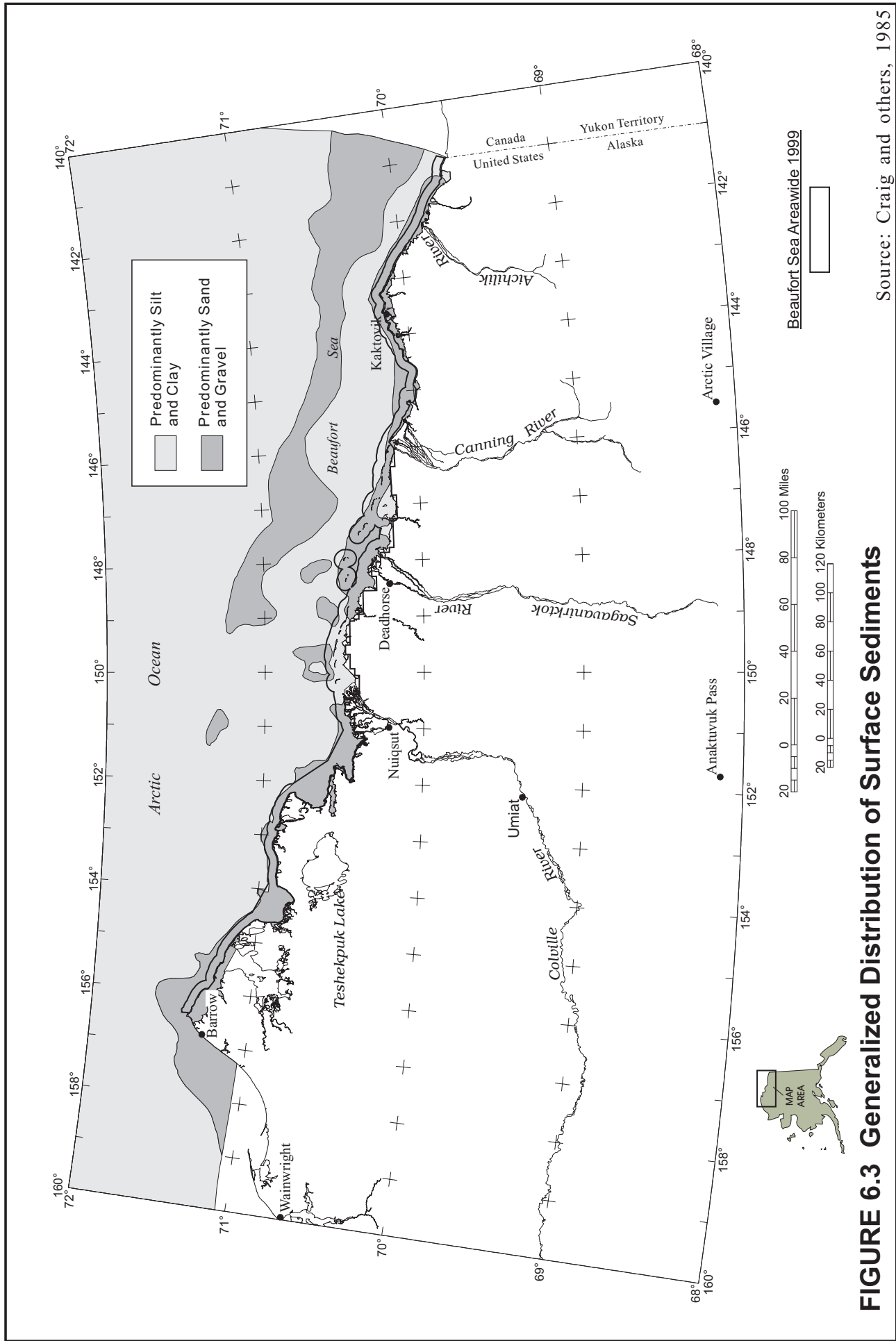


FIGURE 6.3 Generalized Distribution of Surface Sediments

Source: Craig and others, 1985

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Overconsolidated surface sediments are also widespread on the Beaufort shelf (Chamberlain, 1978; Reimnitz and others, 1982). This type of sediment is one that is consolidated beyond that expected from the present overburden pressure, and is produced by freeze-thaw action (Chamberlain, 1978) and compaction by ice gouging (Reimnitz and others, 1980). The freeze-thaw action requires the sediment be frozen after deposition, which for the central Beaufort, has been measured at depths greater than 1 to 2 m (Hunter and Hobson, 1974).

Unstable sediments can move unexpectedly and pose a risk to improperly sited and constructed facilities. Shallow seismic data can reveal some information about the stability of sediments, and shallow core samples profiling sediment type are taken in an area where a facility is to be sited, such as along a proposed pipeline route.

The instability and mass movements of the sediment in the area are also related to the seafloor gradient, low sediment strength where fine-grained sediments retain high amounts of water, sediment loading from waves during storms, and ground motion during earthquakes. Along the shelf, inshore of the 50-meter isobath, the seafloor slope is generally low and, except in the vicinity of Camden Bay, ground motions associated with earthquakes are very low. Thus, except for Camden Bay, the mass movements in water less than 50 m are generally not considered to be a significant hazard to offshore operations (MMS, 1995).

13. Shallow Gas Deposits and Natural Gas Hydrates

Shallow pockets of natural gas have been encountered in boreholes throughout the Arctic, both onshore and offshore. This gas usually exists in association with faults that cut Brookian strata, and as isolated concentrations in the Pleistocene coastal plain sediments (Granz and others, 1982b). The presence of shallow gas has been inferred from studies by Boucher and others (1980), Craig and Thrasher (1982), Sellmann and others (1981), and Grantz and others (1982b). Sediments in which gas has accumulated are a potential hazard if penetrated during drilling as well as for any manmade structures on top of them. The presence of gas may lower the shear strength of the sediments and reduce their ability to support structures (MMS, 1995).

Natural gas hydrates commonly occur offshore under low-temperature, high-pressure conditions (Macleod, 1982) as well as at shallower depths associated with permafrost (Kvenvolden and McMenamin, 1980). Within the sale area, gas hydrates have been found at shallow depths under permafrost along the inner shelf (Sellmann and others, 1981) as well as onshore at Prudhoe Bay (Kvenvolden and McMenamin, 1980). During drilling, the rapid decomposition of gas hydrates can cause a rapid increase in the pressure in the wellbore, gasification of the drilling mud, and the possible loss of well control. If the release of the hydrate gas is too rapid, a blowout can occur, and the escaping gas could be ignited. In addition, the flow of hot hydrocarbons past a hydrate layer could result in hydrate decomposition around the wellbore and the loss of strength of the affected sediments. If this happened and the well were shut-in for a period, the reformation of the hydrates could induce high pressures on the casing string (MMS, 1995).

Because gas hydrates and shallow gas deposits pose risks similar to overpressured sediments, the same mechanisms for blow-out prevention and well control are employed to reduce the danger of loss of life or damage to the environment. For a discussion of oil spill prevention and response, see Section C of this chapter.

B. Likely Methods of Transportation

Assuming that commercial quantities of oil are found in the sale area, it will go to market via the Trans-Alaska Pipeline System (TAPS), a 798-mile pipeline from Prudhoe Bay to Valdez. From Valdez, the oil is transported to markets in the U. S. West Coast, and the U. S. Gulf Coast via tanker. In-field gathering lines bring the oil from individual well sites to processing facilities for injection into TAPS.

Buried or elevated pipelines are the only feasible means for transporting oil and gas from onshore and offshore fields to TAPS. Due to the shallow waters in the sale area, tanker transport is not a viable option. There are several design options for pipelines. The advantages and disadvantages of various transportation options are set forth below. It is possible that a transportation system used for oil or gas from the sale area will

be based upon the use of more than one of the following options discussed below. The mode of transport from a discovery will be an important factor in determining whether or not future discoveries can be economically produced. The more expensive a given transportation option is, the larger a discovery will have to be to be economically viable.

Portions of the sale area lie offshore of ANWR (see Figure 6.4) and NPR-A. Oil and gas facilities are prohibited in ANWR by federal statute and by order of the Secretary of Interior, and in the Teshekpuk Lake area of NPR-A by order of the Secretary of Interior. The status of ANWR could change if Congress amends federal law to permit petroleum exploration and development or if the Secretary of Interior allows a pipeline right-of-way. Likewise, the Secretary could lift the ban on oil and gas activity in the Teshekpuk Lake area of NPR-A. However, this transportation analysis is based on the assumption that these areas will not be available for onshore support of a transportation system.

1. Onshore Pipelines

a. Elevated Pipelines

Elevated pipelines are typically used in North Slope oil field development to prevent heat transfer from the hot oil in the pipeline to frozen soils, since heat would degrade the permafrost. Elevated pipelines are easy to maintain and visually inspect for leaks. To prevent restricting caribou and other wildlife movements, current practice is to build above-ground pipelines to specific heights (five feet) to allow for safe wildlife passage. For the Alpine development project, ARCO may gradually increase the standard five foot minimum to accommodate undulating terrain, thus minimizing vertical bends in the pipeline. To further enhance caribou and human crossing, selected portions of the elevated pipeline may be elevated seven to eight feet near streams and lakes where caribou and human use are high (Parametrix Inc., 1996:2-8).

Roads and adjacent pipelines may inhibit caribou crossing. Pipelines elevated at least five feet have been shown to be effective except when they were in proximity to roads with moderate to heavy traffic (15 or more vehicles/hour). Roads with low levels of traffic and no adjacent parallel pipeline are not significant barriers to movement of caribou. The Alaska Caribou Steering Committee concludes the most effective mitigation is achieved when pipelines and roads are separated by at least 500 ft. Lessees are encouraged (Lease Advisory 10) in planning and design activities to consider the recommendations for oil field design and operations contained in the final report of the Alaska Caribou Steering Committee (Cronin et al., 1994:10).

b. Buried Pipelines

Buried pipelines are feasible in the Arctic provided that the integrity of the frozen soils is maintained. Such pipeline configurations have been used in the Milne Point area. There are some important considerations regarding long sections of buried pipe. First is cost, which depends on length, topography, soils, and distance from the gravel mine site to the pipeline. Second, buried pipe is more difficult to monitor and maintain. However, significant technological advances in leak detection systems have been made which increase the ease with which buried pipelines can be monitored. These systems are described in Section C of Chapter Six. Third, buried pipelines may involve increased loss of wetlands because of gravel fill required to provide a bed and cover for the line. Finally, buried pipelines are sometimes not feasible from an engineering standpoint because of the thermal stability of fill and underlying substrate (Cronin et al., 1994:10).

For its Alpine development project, ARCO constructed an oil pipeline under the Colville River. The Colville River pipeline is scheduled to be operational in 2001 and is designed for a minimum service life of 20 years. The pipeline was installed at a depth of approximately 80 ft. or greater beneath the river bed using horizontal directional drilling methods (Parametrix Inc., 1996:2-12). The pipeline is insulated and will be operated such that the oil temperature will ensure that thaw settlement will be within tolerable limits. The leak detection system will employ real-time monitoring supplemented by the use of inspection pigs (ARCO, 1996:6-9).

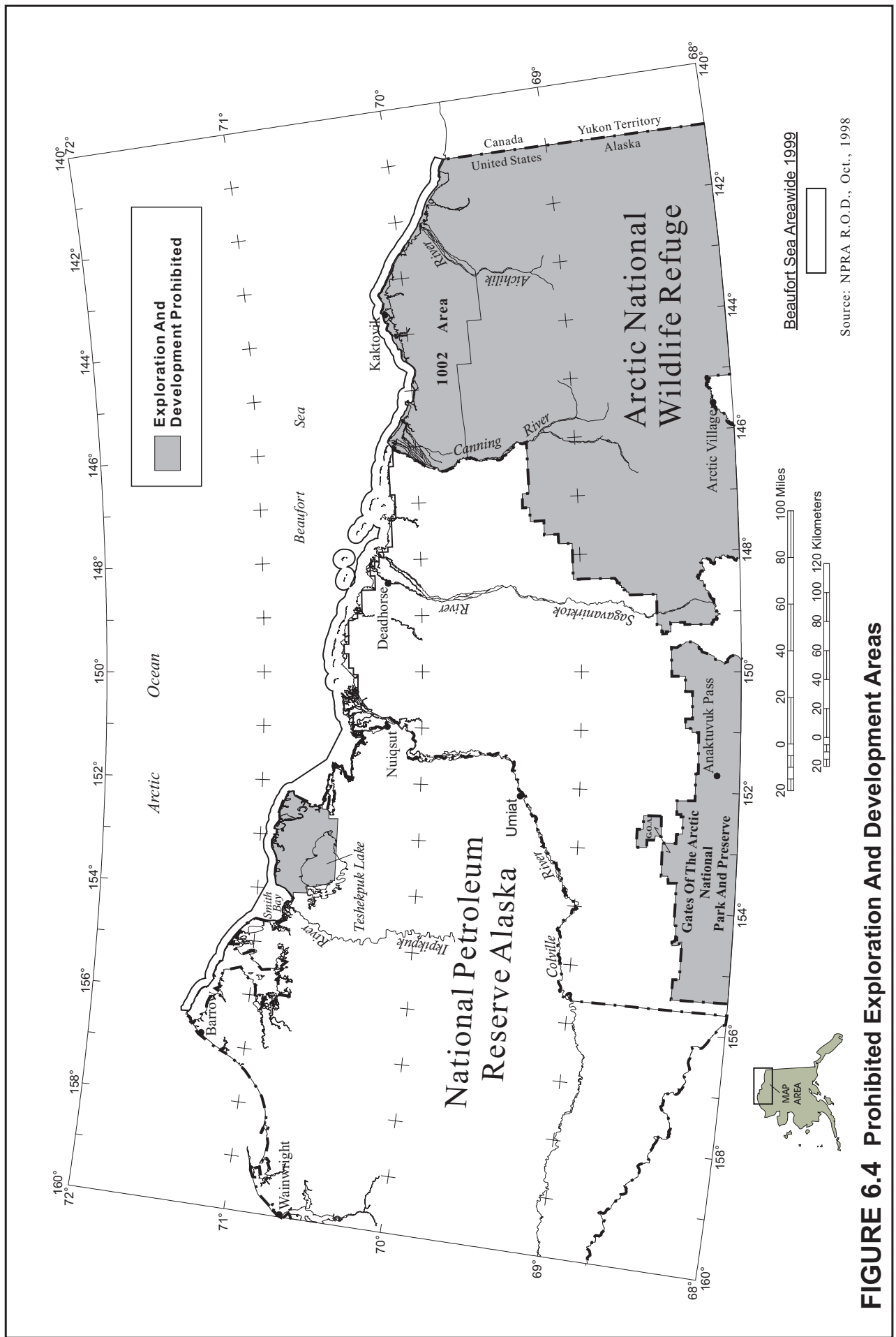


FIGURE 6.4 Prohibited Exploration And Development Areas

2. Offshore Pipelines

The question of how best to transport oil or gas discovered in offshore areas of Alaska's northern coast has been studied for many years. Numerous options have been identified and periodically updated to incorporate technological improvements. The method for bringing offshore oil to shore that is generally most favored by the U.S. Army Corps of Engineers is through directional drilling from onshore locations. There are, however, limits to directional drilling. Factors such as the location of the oil deposit in relation to the drilling rig, the size and depth of the deposit, and most importantly, the geology of the area are all critical elements in determining if directional drilling is feasible (see Appendix E).

If directional drilling is not feasible, oil produced from offshore tracts in the Beaufort Sea could be brought onshore by a number of methods which are discussed below. However, the economic feasibility of development cannot be precisely addressed at the lease sale stage because the existence, location, and extent of any future discovery is not known prior to exploration.

a. Gravel Causeway Without Breaching

Causeways have been used in shallow nearshore areas of the Beaufort Sea to transport oil to shore. A proven method, gravel causeways are generally cost effective. However, because of the high cost of transporting gravel to these remote Beaufort Sea areas, even this relatively low cost type of structure can be prohibitively expensive for the development of marginal fields far offshore (i.e., fields with relatively small reserves, high development costs or a combination of the two) or in deeper waters. As water depths increase, the amount of gravel required to construct a causeway increases significantly. For example, a given length causeway in 15 feet of water requires almost ten times as much gravel as the same structure in five feet of water. Consequently, the feasibility of using gravel in progressively deeper waters depends on the size of the oil reserve.

Transporting oil by means of a continuous solid fill gravel causeway in nearshore areas has several advantages. Pipelines used for transporting oil may be buried in or placed on top of a causeway to facilitate visual inspection and provide a stable operations and logistics base for containing and cleaning up any spills that may occur. Solid gravel causeways can also support the heaviest loads on a year-round basis and provide the additional benefit of year-round access to offshore production facilities. Moreover, causeways are capable of serving as loading and off-loading points for barges bringing fuel, supplies, and equipment into the exploration and production area. They may also be used as corridors for pipelines bringing seawater ashore for reinjection into the ground to maintain onshore oil field pressures.

The construction of continuous fill causeways can have adverse environmental effects depending on the length, orientation, and the specific location of the structure. Disturbance of marine mammals and birds may occur during the construction phase because of noise (U.S. Army Corps of Engineers, 1984:314 and Dames & Moore, 1988:2-27). Placement of gravel in nearshore waters may also result in temporary turbidity plumes (U.S. Army Corps of Engineers, 1984:184) which can affect marine organisms and their habitat. When ice flexes and rides up on a causeway the resultant breaks in the ice may provide an entry point for water and promote strudel scour. Solid-fill causeways may also have an adverse effect on marine and anadromous fish passage, and can alter primary (plankton) production regimes in nearshore estuarine habitat. However, proper siting of causeways can minimize the risk of habitat loss. Although the post-construction environmental effects of continuous solid fill causeways are the subject of differing opinions, it is generally accepted that nearshore causeways have little or no effect on marine mammals. Bowhead and gray whales are occasionally sighted in nearshore areas of the arctic coast but they normally inhabit deeper water further from the shore. The noise level from a causeway is also relatively low, and noise propagates poorly in shallow waters where causeways would normally be constructed.

Although a causeway can cause changes in water circulation patterns affecting temperature and salinity, it is not expected that the deeper water food sources eaten by ringed seals and whales would be

affected by these changes (U.S. Army Corps of Engineers, 1984: 4-226). Based upon past experiences with causeways at West Dock and Endicott, proper siting of causeways can minimize the risk of important habitat loss.

Longer nearshore causeways are considered by some to be environmentally unacceptable because of their potential to alter tidal and nearshore currents, water exchanges, water salinity and temperature. It is feared that alterations of this nature could have significant and long term effects on fishery resources. Depending on where they are sited, causeways, if not properly marked and maintained, can also present a navigational hazard or obstacle where none previously existed. For more on effects of causeways on fish, birds, and marine mammals, see Chapter Five.

b. Gravel Causeway With Breaching

A breached causeway is essentially the same type of structure as described above except that the gravel fill is interrupted by one or more openings of varying length to allow for greater ocean water circulation and fish movement. The existing Endicott and West Dock causeways are examples of this type of design and construction. Although numerous studies have been initiated to determine the environmental impacts of each of these existing structures, there is little consensus concerning the findings. Studies of fish, marine mammals, and sea birds have produced findings from different reviewers ranging from little or no impact to significant habitat degradation or alteration. Studies concerning water quality have also varied in their findings. However, it is generally accepted that during certain periods of the open water season, there are transient changes in nearshore water temperature and salinity. Whether there are adverse environmental impacts resulting from the observed changes remains the subject of controversy.

Breaching a causeway minimizes disruption of water circulation patterns and any resulting changes in water quality that may occur. Detailed studies are available concerning the breached causeways for the West Dock and Endicott projects. In shallower waters, culverts may be used to form the breach, thus reducing overall costs.

Although breaching a causeway reduces the risks of environmental harm from disruption of water circulation patterns, it has certain disadvantages. For example, in comparison to unbreached causeways, breached causeways have higher construction and maintenance costs. The superstructure across the breach, unless the breach is formed by culverts, cannot support unrestricted loads. This could pose safety problems in the event of a well blowout or oil spill which might require rapid movement of very heavy equipment to or from the scene.

c. Subsea Pipeline

Industry experts generally favor subsea pipelines for the transportation of crude oil in the deeper offshore areas of the Arctic region. Although no subsea oil pipelines have been built in the Alaskan Beaufort Sea, the technology exists to construct an offshore pipeline in relatively shallow water to safely transport oil and gas from the Beaufort Sea. BPX has proposed subsea pipelines for the Northstar and Liberty development projects.

Although much more expensive than an onshore pipeline across a portion of the ANWR Coastal Plain or through NPR-A, a main offshore pipeline that completely avoids ANWR and NPRA can be constructed to transport oil from leases offshore from these areas. A careful analysis of the economics and environmental risks would have to be performed to determine which transportation method would be best. This can only be done after a discovery is made and evaluated.

One method of subsea pipeline construction involves winter excavation of a trench in the sea bottom using a plow, dredge, jetting action, or a shovel-type device. The trench could be cut using a plow, dredge, jetting action, or shovel type device, depending on water depths and soil characteristics. The depth of the trench is dictated by the depth of the water, local soil conditions, equipment limitations, and projected hazards expected over the life of the pipeline. Pipe is then laid in the trench, and the trench is back-filled.

In the Beaufort Sea, subsea pipelines would come ashore at the nearest suitable approved landfall and would pass through the nearshore permafrost transition zone inside of or on top of short causeways, through directionally drilled tunnels, or in insulated pipes bedded in gravel-filled trenches. Of the various options for bringing an offshore pipeline through the nearshore permafrost transition zone, installing the pipeline in a dredged trench appears to be the most suitable method, based on current technology. Other methods, such as the use of a causeway, may also be appropriate depending on the length of the shore approach zone, oil temperatures, and the permafrost sensitivity of the local soils (Brown, 1984: Chapter Eight).

A major design consideration for both deep and shallow subsea pipelines in the Arctic Ocean is the risk of damage due to ice and strudel scouring. The ice scour process begins when a floating ice mass with a deep keel is driven against the ocean bottom. These ice masses are driven by environmental forces, including winds, ocean currents, waves, or moving pack ice. Once scouring begins, it will continue until soil or seabed resistance exceeds the strength of the ice keel or the forces pushing the ice (Been, et al.: 179). Subsea pipelines will also experience external loading forces due to ice piling up on the sea floor above the pipeline. The extent to which ice can accumulate on the sea floor above the pipeline will depend on water depth, seasonal weather conditions, and local sea floor conditions. Consequently, where this potential exists, pipelines, must be designed to accommodate this additional external force.

Strudel scour occurs when melting snow and ice on land flow over sea ice as the water is discharged from the river deltas. This fresh water over-flooding can extend several miles seaward from the river deltas and typically occurs in late May to early June. The weight of the fresh water depresses the sea ice where the ice is not bottom fast and causes the ice to crack. The fresh water drains through these cracks. If sufficient static head of fresh water exists, the water drains through the cracks/holes with enough velocity to form a whirlpool waterjet that can scour the seafloor. Individual strudels can vary in size and are typically circular in shape. Strudel scour depths and diameters vary depending on location. In the vicinity of the Northstar pipeline right-of-way they reach depths up to 13 feet below the seabed and diameters vary in size from a few feet up to 89 feet measured at seabed elevation. Pipelines where this potential exists must have adequate strength to span the potential strudel scour conditions in the area (SPCO, 1999).

Subsea pipelines in the Beaufort Sea will also have to be designed to withstand earthquakes. The TAPS and the numerous subsea pipelines in the Cook Inlet area have been designed to avoid damage from earthquakes, and provide good working models for the construction of subsea pipelines in the Beaufort Sea. For more on geophysical hazards, see Section A of this Chapter.

Subsea pipelines are expensive to construct and maintain. A hot oil pipeline buried through the nearshore permafrost transition zone must be designed for upheaval, bucking and thaw settlement. It could also be subject to damage during conditions of severe ice scouring. If a subsea pipeline rupture were to result in an oil spill, detection, containment and cleanup would be more difficult than if the pipeline was on a causeway above the surface of the water or ice. Moreover, maintenance and repair costs for a subsea pipeline are high, as access to the pipeline route maybe limited to winter ice roads or barges during the open water period.

Potential nearshore impacts from subsea pipelines can also be significant. Construction of a pipeline in shallow water and through shoreline areas involves dredging, canal building, or construction of a short causeway out to a deeper water area. These operations have the potential to alter the environment. Although pipeline burial is normally desirable, it is more difficult with certain types of sediment. For example, if the pipeline traverses frozen sediment and the pipeline is not properly insulated, heat transfer from the pipe could result in slumping or the creation of mobile slurries (Baker, 1987:68-74). Pipeline burial, inspection, and maintenance operations can also create significant noise disturbance and changes in water quality that may adversely affect marine mammals. However, there is no evidence of population changes in those species that can be attributed to the much higher and more persistent levels of industrial noise from similar activities in the Canadian Beaufort Sea (U.S. Army Corps of Engineers, 1984: 4-228). Dredging and pipelaying activities may also disturb birds, but to a lesser extent and for a shorter duration than under the causeway alternatives (U.S. Army Corps of Engineers, 1984: 4-316).

Although TAPS is an onshore pipeline, the construction and operation of the TAPS line has provided valuable information on the construction of pipelines in permafrost areas and in the choice of materials to use in arctic conditions. Similarly, the construction of buried pipelines in the now-producing fields on the North Slope has also provided valuable construction and design parameters that can be used in the design of offshore Arctic pipelines.

Subsea pipelines have been successfully constructed using current technology in both shallow and deep water areas including the North Sea, offshore Australia, Gulf of Mexico, and offshore California (Andersen and Misund). No subsea pipeline has yet been constructed in the Alaskan Beaufort Sea although BPX has proposed them for the Northstar and Liberty developments. The unique conditions present in these areas present engineering challenges. Site specific and project specific ice studies, ice loading studies, soil condition analyses, permafrost studies, water current and wave studies, ice and strudel scour studies, external and internal pipeline stress studies, and corrosion control studies will have to be completed in order to design and construct a subsea pipeline.

For the Northstar development project, BPX plans a six-mile subsea pipeline from Seal Island to landfall. A slot will be cut in the ice along the subsea pipeline route. A trench will be excavated in the seafloor for pipeline installation. The trench walls will be approximately vertical in the area of landfast ice and trapezoidal in floating ice areas. Trench depth will range from 7 to 12 feet. The bottom of the trench will be cut to the desired final grade by use of a hydraulic excavator, which discharges the excavated material back into the trench. Tracked equipment will tow pipeline strings to the side of the trench where they will be welded together and lowered through the opening into the seafloor trench. The pipeline will be coated with fusion-bonded epoxy to protect against exterior wall pipeline corrosion. In addition, a cathodic protection system will consist of anodes attached to the pipelines to help prevent corrosion. (U.S. Army Corps of Engineers, 1999:ES-53, ES-74). BPX estimates the maximum depth of ice scour to be 2 feet. along the pipeline route. To help prevent thawing of the permafrost, oil will be cooled to a temperature of 50° F (from 175° F) before being sent through the pipeline (Gipson, 1996).

d. Elevated Pipeline

Elevated pipelines are essentially a series of bridges which support a pipeline, and have the least potential to interfere with lateral fish movements or water circulation (U.S. Army Corps of Engineers, 1984:4-186). Elevated pipelines allow visual monitoring for leaks and maintenance checks. Soil conditions are less of a limiting factor since pilings can be driven through problem soils; and heat transfer to thaw-unstable soils is minimized because the pipeline is not buried in the seabed. However none have been built in the Beaufort Sea.

Several difficulties accompany the use of elevated pipelines in the Beaufort Sea. Access to the pipeline for maintenance and repairs may be difficult during storms, surges, and broken ice conditions in the fall and spring. The pipeline will need to be elevated off the surface of the water because of the potential for ice or wave damage. This significantly adds to the cost of constructing the pipeline and complicates access for maintenance and repairs. In the nearshore permafrost transition zone, the pilings could be subject to jacking and subsidence, both of which could threaten the integrity of the pipeline. Pilings will also be subject to increased stress resulting from ice collisions and ice sheer in deep water areas. A pile-supported pipeline could lead to higher marine noise levels than other transportation alternatives because noise will be conducted into the water through the steel structures supporting the pipeline. However, the effects of pipeline-created noise disturbance on marine mammals will be negligible because of the shallow water depths in the sale area (noise propagates poorly in shallow water) and because marine mammals generally inhabit deeper waters farther from shore (U.S. Army Corps of Engineers, 1984:4-226). Finally, depending on its location, an elevated pipeline could create a significant navigational hazard.

e. Elevated Causeway

This transportation alternative is similar to an elevated pipeline, but would include an accompanying road surface built on the pipeline supports. The road surface would allow for easier year-round maintenance,

inspection, and access to offshore production sites serviced by the structure; but the initial costs associated with construction of the roadway would be substantial.

Like the elevated pipeline alternative discussed above, this option provides for uninterrupted water circulation and improved visual monitoring of the pipeline for leaks. The bridge roadway could also be designed to provide limited containment of small spills on the causeway, and all but the heaviest types of equipment could be transported between shore and production islands on a year-round basis.

The difficulties with the use of an elevated causeway are similar to those discussed above with regard to elevated pipelines, and none have been constructed in the Beaufort Sea. Although access to the pipeline for routine maintenance is improved by the presence of the road surface, access to the supporting superstructure for major repairs may be complicated by broken ice conditions in the fall and spring. The causeway would require the same elevation standard as an elevated pipeline, because of the potential for ice or wave damage. This would substantially add to the cost of constructing the causeway.

Elevated causeways share the same concerns as elevated pipelines. These are the risks of jacking-up and subsidence of the pilings supporting the causeway and increased stress on the pilings caused by ice collisions and ice shear. It is also possible that a pile-supported causeway could lead to higher marine noise levels by conducting noise into the water through the steel structures supporting the road and pipeline. More importantly, noise from traffic on the road could enter the water beneath the bridge. Thus, airborne noise could now enter the water directly, rather than be absorbed by the gravel causeway (U.S. Army Corps of Engineers 1984:4-227). As with elevated pipelines, however, the effects on marine mammals are expected to be negligible because the water depths where the structure would be located in the sale area are extremely shallow and the marine mammals tend to inhabit deep water farther from shore. This type of causeway cannot support unrestricted loads. Access restrictions (weight and size limitations) would limit the loads that could be safely transported over the causeway. Like other causeway alternatives, an elevated causeway could present a navigational hazard.

Construction and maintenance costs are high for this option. During the construction phase, disturbance of birds may occur if pile-driving or other construction work on or near the shore occurs during the summer. Construction of an elevated pipeline would also result in temporary turbidity plumes (U.S. Army Corps of Engineers, 1984: 4-184).

f. Offshore Loading and Ice-Strengthened Tankers

Another transportation option may be offshore loading facilities and ice-strengthened tankers. Oil from offshore leases could be transported via one or more pipelines to a location north of the sale area in the federal OCS, where it could be loaded onto tankers or barges in deeper water. This option could be used in conjunction with oil and gas being produced on federal (OCS) or Canadian leases located further east in the Beaufort Sea. Small tankers require a minimum of 60 feet and super tankers 120 feet of water depth. These depths are not present in state waters.

Structures used for storage and loading of crude oil onto tankers would have to be designed to resist the same ice forces and pressures as production platforms. Conceptual designs include gravity-or pile-founded units. Another design concept is to use production platforms for offshore loading terminals. However, platforms used in this manner would need to be designed to permit tankers to weathervane, have sufficient fendering to prevent a hard collision, and a means for clearing ice rubble in shallow water (Han-Padron, 1984: 7-28, 7-29).

As an example, in September 1986, the VLCC Gulf Beaufort transported 300,000 barrels of oil from the Canadian Beaufort past Point Barrow and through the Bering Strait. The oil was from an extended flow test at the Amauligak discovery well located 43 miles offshore northwest of Tuktoyaktuk. The vessel had a double skin hull for safe operations in the sea ice at that time of the year. If a number of small offshore fields were developed in the eastern Beaufort Sea (including the Canadian Beaufort Sea), tankering oil to market could provide the advantage of serving numerous small fields in both the U.S. and Canada.

The Russians have pioneered a great circle route through the Arctic ocean between the Bering Strait and Europe. In 1978, the Russian icebreaker *Sibir*, with 50,000 shaft horsepower (Shp) and a merchant ship with 9,000 (Shp) successfully negotiated this route at an average speed of 11.5 knots (Gordeichik, 1988). It is anticipated that speeds on this route will increase significantly as icebreakers in the 90,000 to 150,000 (Shp) rating come into service. Although the Northern Sea Route (NSR) used by the Russians is a coastal route, the Russians have discovered that it is easier to negotiate multi-year pack ice than the annual ice accumulations closer to shore. Once the Russians have their NRS open year round on a routine basis in the late 1990s, they expect to begin operating high latitude routes through the Arctic Ocean to better support their international trade (Gordeichik, 1988, Burkov, 1989).

The Russians have demonstrated that it is easier and more cost effective to build and operate ice-strengthened tankers with icebreaker assistance than it is to construct and operate polar class icebreaking tankers. One or two icebreakers can perform a variety of regional tasks including escorting convoys of ice-strengthened tankers. Icebreakers can lead ships year-round to re-supply the oil and gas industry on Alaska's North Slope, to serve deep water production platforms and pipelines in the Chukchi and Beaufort Seas, and to respond to oil spills. This option could complement the use of subsea pipelines by providing routine year-round presence of icebreakers, tankers, and other vessels to serve production platforms and pipelines and to respond to oil spills.

Russia and Finland have been transporting crude oil, natural gas, and refined petroleum products on an expanding seasonal basis in the Arctic Ocean for many years. Other countries such as the U.S. and Canada have also tested this concept.

Tanker transportation has the potential to cause an oil spill. See Section C , Oil Spill Risk, Prevention and Response. Although pipelines have historically had a lower spill rate than the other transportation alternatives, recent studies suggest that double-hulled Arctic tankers currently in use by a number of countries may have a lower spill rate than subsea or onshore pipelines. Spill rates for ice strengthened Arctic tankers are calculated to be at least two orders of magnitude lower than for modern, highly maintained, conventional single hull tankers (Bercha, 1981: 6.1).

The mobility of tankers could allow smaller or widely dispersed fields to be developed if no larger field or groups of fields are discovered to support the construction of a permanent, fixed transportation system. Tankers operating in the Arctic may have to suspend operations during severe ice conditions. Although ice monitoring techniques for the Alaskan Beaufort Sea are currently limited, technology is available to enhance forecasting and monitoring if commercial demands such as those arising from marine navigation increase.

This alternative presents higher risks for marine mammals because passing ships would more readily come into contact with them. They also would create underwater noises caused by propeller cavitation which could adversely effect marine mammals. Moreover, marine mammals are more likely to react to mobile sources of noise than stationary sources (U.S. Army Corps of Engineers, 1984: 4-209).

Any crude oil ultimately produced from sale area tracts will have to be transported to market. It is important to note that the decision to lease oil and gas resources in the state does not authorize the transportation of any oil. If and when oil is found in commercial quantities and production of oil is proposed, final decisions on transporting that oil will be made through the local, state, and federal permitting process. That process will consider any required changes in oil spill contingency planning and other environmental safeguards.

No oil or gas will be transported from the sale leases until the lessee has obtained the necessary permits and authorizations from federal, state, and local governments. The state has broad authority to withhold, restrict, and condition its approval of transportation facilities. In addition, both the North Slope Borough and the federal government have jurisdiction over various aspects of any transportation alternative.

Mitigation Measures.

The following are summaries of some applicable mitigation measures. For the full text of the mitigation measures, see Chapter Seven.

- Avoidance of Beaufort Sea tanker transportation -- use of offshore oil pipelines, rather than tankers, to transport oil from offshore production sites.
- Maintenance of nearshore water quality and fish passage -- The State of Alaska discourages the use of continuous-fill causeways. Environmentally preferred alternatives for field development include use of buried pipelines, onshore directional drilling, or elevated structures. Approved causeways must be designed, sited, and constructed to prevent significant changes to nearshore oceanographic circulation patterns and water quality characteristics (e.g., salinity, temperature, suspended sediments) that result in exceedances of water quality criteria, and must maintain free passage of marine and anadromous fish. Causeways and docks shall not be located in river mouths or deltas. Monitoring programs and mitigation, such as breaching, may be required to achieve intended protection objectives.
- Pipeline Design – Onshore pipelines must be designed and constructed to avoid significant alteration of caribou and other large ungulate movement and migration patterns. All pipelines, including flow and gathering lines, must be designed and constructed to provide adequate protection from water currents, storm and ice and strudel scouring, subfreezing conditions, and other hazards as determined on a case-by-case basis.

C. Oil Spill Risk, Prevention and Response

1. Oil Spill History and Risk

Any time crude oil or petroleum products are handled, there is a risk that a spill might occur. Oil spills associated with the exploration, development, production, storage and transportation of crude oil may occur from well blowouts, pipeline leaks or tanker accidents. Petroleum activities may also generate chronic low volume spills involving fuels and other petroleum products associated with normal operation of drilling rigs, vessels and other facilities for gathering, processing, loading, and storing of crude oil. Spills may also be associated with the transportation of refined products to provide fuel for generators, marine vessels and other vehicles used in exploration and development activities. A worst case oil discharge from an exploration, production, transportation or storage facility is restricted by the maximum tank or vessel storage capacity or by a well's ability to produce oil. Companies do not store large volumes of crude at their facilities on the North Slope. Produced oil is processed and piped out as quickly as possible. This reduces the possible size of a potential spill on the North Slope.

a. Exploration and Production

Spills related to petroleum exploration and production must be distinguished from those related to transportation because the phases have different risk factors and spill histories. Exploration and production facilities in the sale area may include onshore gravel pads; drill rigs; pipelines; and facilities for gathering, processing, storage and moving oil. When spills occur at these facilities, they are usually related to everyday operations such as fuel transfers. Cataclysmic spills are rare at the exploration and production stages because spill sizes are limited by production rates and by the limited amount of crude stored at the exploration or production facility. A well can only spill as much oil as it can produce without assistance. A review of the February 1997 production statistics indicates that the average production rate is 1,511 bpd for producing North Slope fields. Some wells cannot produce without mechanical assistance, and if an accident occurs, oil ceases to flow. The most recent U. S. OCS platform spill rate has been calculated at 0.45 spills (greater than 1000 bbl) per billion bbl, based on trend analysis for 1964-1992 (Anderson and LaBelle, 1994).

The most dramatic form of spill can occur during a well blowout, which can take place when high pressure gas is encountered in the well and secondary well control measures, such as increasing the weight of

the drilling mud, are not effective. The result can be that oil, gas, or mud is suddenly and violently expelled from the well bore, followed by uncontrolled flow of fluids or gas from the well. Blowout preventers, which immediately close off the open well to prevent or minimize any discharges, are required for all drilling and work-over rigs and are routinely inspected by the AOGCC.

A blowout that results in an oil spill is extremely rare and has never occurred in Alaska. However, natural gas blowouts have occurred. From 1974 to 1997 an estimated 3,336 wells were drilled on the North Slope. There have been six documented instances of loss of secondary well control with a drill rig on the well. This equates to 1.8 blowouts per 1000 wells (Mallary, 1998). A gas blowout occurred in 1992 at the Cirque No. 1 well. The accident occurred while ARCO workers were drilling an exploratory well and hit a shallow zone of natural gas. Drilling mud spewed from the well and natural gas escaped. It took two weeks to plug the well (Anchorage Times, 1992). In 1994, a gas kick occurred at the Endicott field 1-53 well. BPX was forced to evacuate personnel and shut down most wells on the main production island. No oil was released to the surface, as the well had not yet reached an oil-bearing zone. There were no injuries, and the well was killed three days later by pumping heavily-weighted drilling muds into it (Schmitz, 1994; Anchorage Daily News, 1994a).

b. Pipelines

There are no subsea pipeline spill statistics available for the Beaufort Sea because there currently are no offshore subsea pipelines in the lease sale area. The Northstar project will include the first offshore pipeline. The onshore pipeline system that would receive production from offshore if any crude is discovered and produced, includes gathering lines and pipelines to carry the crude to treatment facilities and to Pump Station 1. At that point the oil enters TAPS for transport to the port of Valdez for tanker transport outside of Alaska. According to the most recent statistics available, the U. S. OCS pipeline spill rate for spills (greater than 1,000 bbl) is 1.32 spills per billion barrels transported based on the entire record for 1964-1992 (Anderson and LaBelle, 1994). Pipelines vary in size, length and amount of oil contained. A 14-inch pipeline can contain about 1,000 bbl per mile of pipeline length. Under static conditions, if oil were lost from a five-mile stretch of this pipeline (a hypothetical distance between emergency block valves), a maximum of 5,000 bbl of oil could be discharged if the entire volume of oil in the segment drained from the pipeline.

In January 1994, a pipeline break occurred at a Prudhoe Bay drill site. Investigation showed the failure of the line was caused by wind-induced vibration and the automatic safety valve and alarm had been turned off. Response to the oil spill was swift in containment and cleanup. Most of the oil flowed into an impoundment area, and approximately 360 bbl were recovered of an estimated 300-400 bbls spilled. Further investigation found four other wells in the Prudhoe Bay eastern operating area with safety valves turned off (Alaska Journal of Commerce, 1994:4, and Schmitz, 1994). A leak in a Kuparuk pipeline carrying oil to a processing facility was also discovered in 1994. The cause of the two-foot crack in the line has not yet been determined (Schmitz, 1994). The oil flow was shut off and the line depressurized. The breached pipeline carries around 20,000 bbl per day from two drilling sites. About 6,000 square feet of surrounding tundra was affected, but there was no danger to the nearby Ugnuravik River (Anchorage Daily News, 1994:D).

On April 20, 1996 Alyeska Pipeline Company discovered crude oil in an access vault (similar to a manhole) near check valve 92 which is located about 90 miles north of Glennallen. Alyeska and the State Pipeline Coordinators Office (SPCO) activated the Incident Command System and dispatched staff to the site and to the emergency operations control center at Alyeska's Anchorage offices. Throughput in the TAPS was reduced from 1.5 million to 850,000 barrels per day during the response. The leak came from a faulty plug on a six-inch bypass line. Check valve 92 is buried about 16 ft. below the surface. Alyeska drilled two holes downhill from the valve and removed dirt from around the line in an effort to locate the source of the leak and to determine the extent of impact. The company completed repairs April 25 and recovered about 500 gallons of crude oil from two metal culverts and contaminated soils (ADEC, 1996).

On June 11, 1999, a pipeline spill occurred at ARCO Drill Site 14. The well line from well #29 developed a hole leaking about 40 gallons of oil. An oil-water mixture sprayed out across the pad. The majority of the oil remained on the pad with a fine spray reaching tundra on the opposite, downwind side. A

light spotty sheen was visible on a nearby pond. Mitigation measures include placing sorbent boom in the pond and keeping wildlife away from the area. A tundra remediation plan is pending (ADEC, 1999).

c. Marine Terminals

There are no marine terminals on the North Slope due to the presence of ice for most of the year. The Valdez terminal receives North Slope crude through TAPS, stores it and loads it onto tanker vessels for transport to the west coast of the United States and Pacific Rim. Most North Slope crude is transported to the U.S. west coast.

The Valdez terminal has maintained records of all spills since startup in 1977. From June 1977 to November 1994, there have been 48 spills greater than 55 gallons from terminal equipment or systems. Of these spills 34 (70 percent) were to land, 10 incidences (20 percent) were to water, and 4 (8 percent) were to both land and water. The causes have been personnel error and equipment failure or unknown. Twenty-six (42 percent) of the spills were North Slope crude, 19 (38 percent) were diesel fuel or lubricants, and 8 (11 percent) were chemicals and water (Alyeska Pipeline Service Co., 1996).

Petroleum hydrocarbons may enter Port Valdez harbor from ballast water that is off-loaded from incoming tankers. The water is treated to remove residual petroleum hydrocarbons and then discharged via a submarine diffuser into the inlet (Jarvella 1987:582). A four year, pre- and post-operational study undertaken by the University of Alaska (Jarvella 1987, citing Colonell 1980) concluded that no adverse effects on the fjord were presently evident (Jarvella 1987:582). Monitoring continues under National Pollutant Discharge Elimination System (NPDES) permits.

The stationary nature of exploration, production and terminal facilities and the predictability of maximum spill rates based on production rates and storage amounts somewhat simplifies the development and implementation of oil spill contingency plans for those facilities. In contrast, the mobile nature of tankers, the large volumes carried and the exposure to marine hazards places tankers at higher risk for oil spills. A badly damaged tanker can spill millions of gallons of oil in a matter of hours.

d. Tanker Vessels

North Slope crude oil is carried from the Port of Valdez to the U.S. west coast and to the Nikiski refinery in Cook Inlet. According to the most recent statistics, worldwide tanker spill rates have stayed constant at 1.30 spills (greater than 1,000 bbl) per billion bbl transported for 1974-1992. For U.S. tankers the spill rate is calculated at 1.30 spills per billion barrels transported for the period 1974-1992. The tanker spill rate for North Slope crude oil has been 1.10 spills per billion bbl for the period 1977-1992 (Anderson and Labelle, 1994). A tanker accident can result in the release of large quantities of oil in a short time, causing severe environmental damage. An oil spill in a marine water setting is also much more difficult to contain than one on land since ocean currents and tidal actions carry the oil over a much larger area.

During the summer of 1987, the tanker *Glacier Bay* spilled between 2,350-3,800 bbl of North Slope crude oil being transported into Cook Inlet for processing at the Nikiski Refinery (ADEC, 1988:1). Less than ten percent of the oil was recovered, and the spill interrupted commercial fishing activities in the vicinity of Kalgin Island during the peak of the red salmon run. Although not on the scale of the *Exxon Valdez* spill, this spill focused attention on oil spill response and cleanup capabilities in Cook Inlet.

An example of the potential magnitude of a tanker spill is the March 1989 *Exxon Valdez* spill, the largest recorded spill in U.S. waters (nearly 261,900 bbl). Oil from the *Exxon Valdez* contaminated fishing gear, fish, and shellfish, killed numerous marine birds and mammals, and led to the closure or disruption of many Prince William Sound, Cook Inlet, Kodiak, and Chignik fisheries (Alaska Office of the Governor 1989 "Exxon Valdez Oil Spill Information Packet"). Effects of the oil spill on fish and other wildlife can be found in this finding in the section entitled Cumulative Effects.

The spills from the *Glacier Bay* and the *Exxon Valdez* were not effectively contained, and the effectiveness of the cleanup efforts remains the subject of controversy. In the case of the *Glacier Bay* spill in Cook Inlet, tidal currents and confusion concerning who would respond to the spill caused response problems.

During the *Exxon Valdez* spill in Prince William Sound, the sheer size of the spill quickly overtaxed available cleanup resources at a time when response plans had not been updated or practiced and equipment stockpiles were not sufficient nor easily accessible.

In May 1994, a cracked hull in the *Eastern Lion* allowed approximately 8,400 gallons of crude oil to leak into the port of Valdez while the vessel was berthed at the marine terminal. As a result of analyzing response methods, Alyeska Pipeline purchased shallow draft boats to allow access of tow boom to the shallow duck flats area and a new ramp is to be built at the fish hatchery to move booms more efficiently from shore to water (Alaska Journal of Commerce, 1994a).

The *Glacier Bay* and *Exxon Valdez* incidents demonstrated that preventing catastrophic tanker spills is easier than cleaning them up and focused public, agency, and legislative attention on the prevention and cleanup of oil spills. Numerous changes were made on both the federal and state levels. At the state level, new statutes created the oil and hazardous substance spill response fund (AS 46.08.010), established the Spill Preparedness and Response (SPAR) Division of ADEC (AS 46.08.100), and increased financial responsibility requirements for tankers or barges carrying crude oil up to a maximum of \$100 million (AS 46.04.040(c)(1)). The discussion of regulations and laws regarding oil spills is presented later in this section.

Tankers heading south out of Hinchinbrook Entrance stay 50 to 200 miles offshore, depending on each company's route and sea and ice conditions. The U. S. Coast Guard does not establish the route. Since November 1994, new USCG safety regulations for tankers operating in the Prince William Sound area, especially through the Valdez Narrows, require tankers to add a third tugboat to accompany tankers when winds exceed 20 knots instead of 30 knots. Shippers voluntarily reduced tanker speed through the Narrows from 6 knots to 5 knots to enable a tugboat attached to the back of a tanker to guide the tanker more effectively.

An independent risk assessment study of oil tankers traversing Prince William Sound concludes that current safeguards instituted after the *Exxon Valdez* oil spill have significantly reduced the risks of oil spills. The study recommended a number of additional improvements to further reduce risk, and the TAPS shippers are instituting many new safeguards. The shippers are working with Alyeska to:

- Charter a high-powered tug for deployment at Cape Hinchinbrook to reduce the risk of a tanker grounding;
- Upgrade the current fleet of tugs with at least two newly enhanced tugs, incorporating risk assessment recommendations and the state's new "best available technology" regulations;
- Revise tug operating procedures for Valdez Narrows to minimize dangers of human error identified in the risk assessment;
- Work with the U.S. Guard and ADEC to implement a new escort system using prepositioned tugs in central Prince William Sound to reduce the risk of a collision;
- Test new tractor tugs for use in Valdez Narrows; and
- Place new tractor tugs in service as soon as possible if their performance is equal to or better than the tethered-tug system currently in use.

2. Regulation of Oil Spill Prevention and Response

a. Federal Statutes and Regulations

Section 105 of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) (42 U.S.C. §9605), and section 311(c)(2) of the Clean Water Act as amended (33 U.S.C. § 1321(c)(2)) require environmental protection from oil spills. CERCLA regulations contain the National Oil and Hazardous Substances Pollution Contingency Plan (40 C.F.R. § 300). Under these regulations, the operator of an oil facility must plan to prevent and immediately respond to oil and hazardous substance spills and must be financially liable for any spill cleanup. If the pre-designated Federal On-Scene Coordinator

(FOSC) determines that neither timely nor adequate response actions are being implemented, the federal government will take charge of the response then seek to recover cleanup costs from the responsible party.

The Oil Pollution Act of 1990 (OPA 90) requires the development of facility and tank vessel response plans by the industry and government planning to coordinate federal, regional, and local government preparation efforts with the industry. OPA 90 amended the Clean Water Act (Section 311(j)(4)), which established area committees and area contingency plans as the primary components of the national response planning structure. In addition to human health and safety, these area committees have three primary responsibilities:

1. prepare an area contingency plan;
2. work with state and local officials on contingency planning and preplanning of joint response efforts, including procedures for mechanical recovery, dispersal, shoreline cleanup, protection of sensitive areas, and protection, rescue and rehabilitation of fisheries and wildlife; and
3. work with state and local officials to expedite decisions for the use of dispersants and other mitigating substances and devices.

In Alaska, the area committee has incorporated state and local agency representatives, and the jointly prepared plans coordinate the response activities of the various governmental entities that have responsibilities regarding oil spill response. The area contingency plan for Alaska is the Unified Plan and is discussed below. Since Alaska is so large and geographically diverse, the federal agencies have found it necessary to prepare sub-area contingency plans. These plans have been combined with the government contingency plans required by state law and are discussed later in this section.

OPA 90 requires that oil facility operators provide proof of financial responsibility. The Oil-Spill Financial Responsibility (OSFR) regulations are administered by the Minerals Management Service (MMS) and apply to facilities used to explore for, produce or transport crude oil or natural gas located on the Outer Continental Shelf (OCS), state waters seaward from the line of ordinary low water along that portion of the coast that is indirect contact with the open sea, and certain coastal inland waters. The OSFR requirements apply to facilities that have a worst-case oil spill discharge potential of greater than 1,000 bbls. The potential responsible party's OSFR proof may take several forms, including insurance and surety bonds. In general, the amount of required coverage ranges from \$10 to \$150 million, depending on the calculated volume of the facility's worst-case oil spill discharge potential.

OSFR REQUIREMENTS FOR NON-OCS LANDS

WORST CASE OIL SPILL DISCHARGE VOLUME	AMOUNT OF OSFR
Over 1,000 but not more than 10,000 bbls	\$10 million
Over 10,000 but not more than 35,000 bbls	\$35 million
Over 35,000 but not more than 70,000 bbls	\$70 million
Over 70,000 but not more than 105,000 bbls	\$105 million
Over 105,000 bbls	\$150 million

These federal requirements apply to facilities on the OCS and on state submerged lands as well. The State of Alaska has a well-established financial responsibility program that differs from the federal program in both the type of facilities covered and the amount of financial responsibility required. The state program is discussed later in this section. The programs are separate and distinct until specific agreements are developed to coordinate the two programs. State and federal agencies are working together to accomplish this.

OPA 90 also created two citizen advisory groups, the Prince William Sound and the Cook Inlet Regional Citizens Advisory Councils. These non-profit organizations provide citizen oversight of terminal and tanker operations that may affect the environment in their respective geographic areas. They also foster a long

term partnership between industry, government and citizens and carry out responsibilities identified in section 5002 of OPA 90. The groups provide recommendations on policies, permits and site-specific regulations for terminal and tanker operations and maintenance and port operations, monitoring terminal and tanker operations and maintenance, and reviewing contingency plans for terminals and tankers and standards for tankers.

The Prince William Sound Regional Citizens Advisory Council (PWSRCAC) consists of 18 member organizations, including communities impacted by the *Exxon Valdez* oil spill, a Native regional corporation and groups representing fishing, aquaculture, environmental, tourism and recreation interests in the impacted area. PWSRCAC is certified under OPA 90 and operates under a contract with Alyeska. The contract, which is in effect as long as oil flows through TAPS, guarantees the council's independence, provides annual funding, and ensures the PWSRCAC the same access to terminal facilities as state and federal regulatory agencies.

b. Alaska Statutes and Regulations

As discussed in Chapter One, ADEC is the state agency responsible for implementing state oil spill response and planning regulations under AS46.04.030. The industry must file oil spill prevention and contingency plans with ADEC before operations commence. ADNRR and ADF&G review and comment to ADEC regarding the adequacy of the industry oil discharge prevention and contingency plans (C-plans).

According to both federal and state law oil and gas facilities must have an approved C-plan before beginning operations. AS 46.04.030 provides that no person may:

1. operate an oil terminal facility, a pipeline, or an exploration or production facility, a tank vessel, or an oil barge, or
2. permit the transfer of oil to or from a tank vessel or oil barge, unless an oil discharge prevention and contingency plan has been approved by ADEC, and the operator is in compliance with the plan (AS 46.04.030(a),(b),(c)).

Parties with approved plans are required to have sufficient oil discharge containment, storage, transfer, cleanup equipment, personnel, and resources to meet the response planning standards for the particular type of facility, pipeline, tank vessel, or oil barge (AS 46.04.030(k)). Examples of these standards are:

- The operator of an oil terminal facility must be able to "contain or control, and clean up" a spill volume equal to that of the largest oil storage tank at the facility within 72 hours. That volume may be increased by ADEC if natural or manmade conditions exist outside the facility which place the area at high risk (AS 46.04.030(k)(1)).
- Operators of exploration or production facilities, or pipelines, must be able to "contain, control, and cleanup the realistic maximum oil discharge within 72 hours." (AS 46.04.030(k)(2)). The "realistic maximum oil discharge" means "the maximum and most damaging oil discharge that [ADEC] estimates could occur during the lifetime of the tank vessel, oil barge, facility, or pipeline based on (1) the size, location, and capacity; (2) ADEC's knowledge and experience with such; and (3) ADEC's analysis of possible mishaps." (AS 46.04.030(q)(3)).
- For crude oil tank vessels and oil barges with a cargo volume of less than 500,000 bbls, the plan holder must be able, at a minimum, to contain or control, and clean up a discharge of 50,000 bbls within 72 hours (AS 46.04.030(k)(3)(A)). For capacities of 500,000 bbls or more, the cleanup volume must be 300,000 bbls within 72 hours (AS 46.04.030(k)(3)(B)). Additionally, all crude oil tank vessel operators must also maintain equipment, personnel, and other resources as necessary to control or contain and clean up a realistic maximum discharge within the shortest possible time (AS 46.030(k)(3)(C)).

Discharges of oil or hazardous substances must be reported to ADEC on a time schedule depending on the volume released, whether the release is to land or to water, and whether the release has been contained by a secondary containment or structure. For example, any discharge of oil to water in excess of 55 gallons on

land not within an impermeable secondary containment area or structure must be reported as soon as the operator has knowledge of the discharge (18 AAC 75.300(a)(1)(B) and (C)).

The discharge must be cleaned up to the satisfaction of ADEC, using methods approved by ADEC. If ADEC determines that clean up efforts are inadequate, the department will either order the person engaged in cleanup operations to use additional methods or to cease cleanup activities, or authorize other agents to begin cleanup activities, or both (18 AAC 75.337(a)). ADNRR and ADF&G advise ADEC regarding the adequacy of cleanup.

A C-plan must describe the existing and proposed means of oil discharge detection, including surveillance schedules, leak detection, observation wells, monitoring systems, and spill-detection instrumentation. AS 46.04.030; 18 AAC 75.425(e)(2)(E). C-plans for exploration facilities should include a description of methods for responding to and controlling blowouts; the location and identification of oil spill cleanup equipment; the location and availability of suitable drilling equipment; and an operations plan to mobilize and drill a relief well. If development and production should occur, additional contingency plans must be filed for each facility prior to commencement of activity, as part of the permitting process. Any vessels transporting crude oil from the potential development area must also have an approved contingency plan. A C-plan and its preparation, application, approval, and demonstration of effectiveness requires a major effort on the part of facility operators and plan holders. The C-plan must include a response action plan, a prevention plan, and supplemental information to support the response plan (18 AAC 75.425). These plans are described below.

The Response Action Plan (18 AAC 75.425(e)(1) Part 1) must include an emergency action checklist of immediate steps to be taken if a discharge occurs. The checklist must include:

1. names and telephone numbers of people within the operator's organization who must be notified, and those responsible for notifying ADEC;
2. information on safety, communications, and deployment, and response strategies;
3. specific actions to stop a discharge at its source, to drill a relief well, to track the location of the oil on open water, and to forecast the location of its expected point of shoreline contact to prevent oil from affecting environmentally sensitive areas;
4. procedures for boom deployment, skimming or absorbing, lightening, and estimating the amount of recovered oil;
5. plans, procedures, and locations for the temporary storage and ultimate disposal of oil contaminated materials and oily wastes;
6. plans for the protection, recovery, disposal, rehabilitation, and release of potentially affected wildlife; and
7. if shorelines are affected, shoreline clean up and restoration methods.

The Prevention Plan (18 AAC 75.425(e)(2) Part 2) must:

1. include a description and schedule of regular pollution inspection and maintenance programs;
2. provide a history and description of known discharges greater than 55 gallons that have occurred at the facility, and specify the measures to be taken to prevent or mitigate similar future discharges;
3. provide an analysis of the size, frequency, cause, and duration of potential oil discharges, and any operational considerations, geophysical hazards, or other site-specific factors, which might increase the risk of a discharge, and measures taken to reduce such risks.

The Supplemental Information Section (18 AAC 75.425(e)(3) Part 3) must:

1. include bathymetric and topographic maps, charts, plans, drawings, diagrams, and photographs, which describe the facility, show the normal routes of oil cargo vessels, show the locations of storage tanks, piping, containment structures, response equipment, emergency towing equipment, and other related information;
2. show the response command system; the realistic maximum response operation limitations such as weather, sea states (roughness of the sea), tides and currents, ice conditions, and visibility restrictions;

the logistical support including identification of aircraft, vessels, and other transport equipment and personnel;

3. include a response equipment list including containment, control, cleanup, storage, transfer, lightering, and other related response equipment;
4. provide non-mechanical response information such as in situ burning or dispersant, including an environmental assessment of such use; and
5. provide a plan for protecting environmentally sensitive areas and areas of public concern.

The current statute allows the sharing of oil spill response equipment, materials, and personnel among plan holders. ADEC determines by regulation the maximum amount of material, equipment, and personnel that can be transferred, and the time allowed for the return of those resources to the original plan holder (AS 46.04.030(o)). The statute also requires the plan holders to “successfully demonstrate the ability to carry out the plan when required by [ADEC]”. (AS 46.04.030(r)(2)(E)). ADEC regulations require that exercises shall be conducted to test the adequacy and execution of the contingency plan. No more than two exercises are required annually, unless the plan proves inadequate. ADEC may, at its discretion, consider regularly scheduled training exercises as discharge exercises. (18 AAC 75.485(a) and (d)).

Holders of approved contingency plans must provide to the state proof of their financial ability to respond (AS 46.04.040). Financial responsibility may be demonstrated by one or a combination of 1) self-insurance; 2) insurance; 3) surety; 4) guarantee; 5) approved letter of credit; or 6) other ADEC-approved proof of financial responsibility. (AS 46.04.040(e)). Operators must provide proof of financial responsibility acceptable to ADEC as follows:

- for crude oil terminals: \$50 million in damages per incident.
- for a non-crude oil terminal: \$25 per incident for each barrel of total non-crude oil storage capacity at the terminal or \$1 million, whichever is greater, with a maximum of \$50 million.
- for pipelines and offshore exploration or production facilities: \$50 million per incident.
- for onshore production facilities: \$20 million per incident.
- for onshore exploration facilities: \$1 million per incident.
- for crude oil vessels and barges: \$300 per incident, for each barrel of storage capacity or \$100 million, whichever is greater.
- for non-crude oil vessels and barges: \$100 per barrel per incident or \$1 million, whichever is greater, with a ceiling of \$35 million. AS 46.04.040(a),(b),(c).
- The coverage amounts are adjusted every third year based on the Consumer Price Index.
- AS 46.04.045.

In accordance with AS 46.04.200, ADEC must prepare, annually review, and revise the statewide master oil and hazardous substance discharge prevention and contingency plan. The plan must identify and specify the responsibilities of state and federal agencies, municipalities, facility operators, and private parties whose property may be affected by an oil or hazardous substance discharge. The plan must incorporate the incident command system, identify actions to be taken to reduce the likelihood of occurrence of “catastrophic” oil discharges and “significant discharges of hazardous substances” (not oil), and designate the locations of storage depots for spill response material, equipment, and personnel. The state master plan has been combined with the federally required area plan to create the “Alaska Federal/State Plan for Response to Oil and Hazardous Substance Discharges/Releases,” also known as the Unified Plan (ADEC, 1994).

ADEC must also prepare and annually review and revise a regional master oil and hazardous substance discharge prevention and contingency plan (AS 46.04.210). The regional master plans must contain the same elements and conditions as the state master plan but are applicable to a specific geographic area. The regional plans are being developed in conjunction with the federally required sub-area plans as “Sub-Area/Regional Contingency Plans” for each of the ten designated contingency planning areas. The sub-area plan for the North Slope is in preparation at this time.

3. Oil Spill Prevention

A number of measures contribute to the prevention of oil spills during the exploration, development, production, and transportation of crude oil. Some of these prevention measures are presented as mitigation measures in Chapter Four, and some are discussed at the beginning of this section. Prevention measures are also described in the oil discharge prevention and contingency plans that the industry must prepare prior to beginning operations. Thorough training, well-maintained equipment and routine surveillance are important components of oil spill prevention.

a. Exploration and Production

The oil industry employs many techniques and operating procedures to help reduce the possibility of spilling oil. The techniques that may be used during exploration include:

- Use of existing facilities and roads.
- Waterbody protection, including proper location of onshore oil storage and fuel transfer areas.
- Use of proper fuel transfer procedures.
- Use of secondary containment, such as impermeable liners and dikes.
- Proper management of oils, waste oils, and other hazardous materials to prevent ingestion by bears and other wildlife.

Should development occur, additional measures include:

- Consolidation of facilities.
- Placement of facilities away from fishbearing streams and critical habitats.
- Proper installation and maintenance of blowout prevention equipment, including subsea safety valves for offshore wells.
- Siting pipelines to facilitate spilled oil containment and cleanup.
- Installation of pipeline leak detection and shutoff devices.

Each exploration or development well has a blowout prevention program that is developed before the well is drilled. Operators review bottom-hole pressure data from existing wells in the area and seismic data to learn what pressures might be expected in the well to be drilled. Engineers use this information to design a drilling mud program with sufficient hydrostatic head to overbalance the formation pressures from surface to the total depth of the well. They also design the casing strings to prevent various formation conditions from affecting well control performance. Blowout prevention (BOP) equipment is installed on the wellhead after the surface casing is set and before actual drilling begins. BOP stacks are routinely tested in accordance with government requirements (BPX, 1996).

Wells are drilled according to the detailed plan. Drilling mud and well pressures are continuously monitored, and the mud is adjusted to meet the actual wellbore pressures. The weight of the mud is the primary well control system. If a kick (sudden increase in well pressure) occurs, the well is shut-in using the BOP equipment. The BOP closes off and contains fluids and pressures in the annulus and in the drillpipe. Technicians take pressure readings and adjust the weight of the drilling mud to compensate for the increased pressure. BOP drills are performed routinely with all crews to ensure wells are shut-in quickly and properly. Rig foremen, tool pushers, drillers, derrick men and mud men all have certified training in well control that is renewed annually (BPX, 1996).

If well control is lost and there is an uncontrolled flow of fluids at the surface, a well control plan is devised. The plan may include instituting additional surface control measures, igniting the blowout, or drilling a relief well. Regaining control at the surface is faster than drilling a relief well and has a high success rate. A blowout may bridge naturally due to the pressure drop across the formations. Under these conditions, reservoir formations flow to equalize pressure, and the resulting bridging results in decreased flow at the surface. The exact mechanical surface control methods used depend on the individual situation. Operators

may pump mud or cement down the well to kill it; replace failed equipment, remove part of the BOP stack and install a master valve; or divert the flow and install remotely-operated well control equipment (BPX, 1996).

At the same time operators are considering mechanical surface control methods, they begin planning to drill a relief well. They assess the situation and determine the location for the relief well and plan the logistics necessary to move another drill rig to the site. Conditions may require the construction of an ice or gravel pad and road. The operator will look for the closest appropriate drill rig. If the rig is in use, industry practice dictates that, when requested, the operator will release the rig for emergency use. Arranging for and drilling a relief well could take from 10 to 15 weeks depending on weather, cause of the blowout, choice of surface location and depth of the well (BPX, 1996).

Leak detection systems and effective emergency shut-down equipment and procedures are essential in preventing discharges of oil from any pipeline which might be constructed in the sale area. Once a leak is detected, valves at both ends of the pipeline, as well as intermediate block valves, can be manually or remotely closed to limit the amount of discharge. The number and spacing of the block valves along the pipeline will depend on the size of the pipeline and the expected throughput rate (Nessim and Jordan, 1986:68). Industry on the North Slope currently uses the volume balancing method. This method involves comparing input volume to output volume.

The technology for monitoring pipelines is continually improving. Leak detection methods being researched outside Alaska include acoustic monitoring, pressure point analysis, and combinations of some or all of the different methods (Yoon, Mensik, and Luk 1988). The approximate location of a leak can be determined from the sensors along the pipeline. A computer network is used to monitor the sensors and signal any abnormal responses. In recent years, computer based leak detection through a Real-Time Transient Model (RTTM) to minimize spills has come into use. This technology can minimize spills from both new and old pipelines by measuring the pipeline flow (in and out), product density, pressures, and temperatures along the pipeline (Yoon and Mensik, 1988).

A similar technology for detecting leaks in oil and gas pipelines is termed Pressure Point Analysis (PPA). The method uses measured changes in the pressure and velocity of the fluid flowing in a pipeline to detect and locate leaks. PPA has successfully detected holes as small as 1/8-inch in diameter within a few seconds to a few minutes following a rupture (Farmer, 1989:23). Automated leak detection systems such as PPA operate 24 hours per day and can be installed at remote sites. Information from the sensors can be transmitted by radio, microwave, or over a hard wire system.

Design and use of “smart pigs,” data collection devices that are run through the pipeline while it is in operation, has greatly enhanced the ability of a pipeline operator to detect internal and external corrosion and differential pipe settlement in pipelines. These pigs can be sent through the pipeline on a regular schedule to detect changes over time and give advance warning of any potential problems. The TAPS operation has pioneered this effort for Arctic pipelines. The technique is now available for use worldwide and represents a major tool for use in preventing pipeline failures.

ARCO Alaska has implemented a comprehensive FLIR (Forward Looking InfraRed) pipeline monitoring program in the Kuparuk oil field to assist in detecting pipeline leaks and corrosion. InfraRed sensors have the ability to sense heat differentials. Since Kuparuk oil flows from the ground at temperatures in excess of 100°F, a leak shows up as a “hot spot” in a FLIR video. In addition, water-soaked insulation surrounding a pipeline is visible because of the heat transfer from the hot oil to the water in the insulation and finally to the exterior surface of the pipeline. FLIR is effective 80 percent of the time in discovering water-soaked insulation areas that have produced corrosion on the exterior wall of the pipeline (ARCO, 1998).

FLIR also has applications in spill response and was used to image spills at both Prudhoe Bay and Kuparuk. The video frames were processed and registered into a GIS map database. The map database with the overlaid picture of the spill site was then used to quickly and accurately determine the area of the spill. This action allowed quick and accurate reporting of the spill parameters to the appropriate agencies. The video footage of the spill area allowed the incident command team to receive near real-time information in IR and color. This information permitted timely decisions to be made and the results of those decisions to be

reviewed with the subsequent fly over zone site. Various agencies involved the process were able to see and verify the results of cleanup process (ARCO, 1998).

For the Northstar project, the pipeline will be monitored on a continuous basis by the Supervisory Control and Data Acquisition (SCDA) system and operation personnel will be provided with real-time information on pipeline status. Both USDOT and MMS require SCDA for sub-sea pipelines. This system can detect changes in flow rate to 0.15 percent of daily flow volume. To obtain early warning of potential leak points, pipelines would be checked periodically by inspection pigs. Visual surveys would be performed to detect chronic leaks below the threshold of the SCADA system. Weekly aerial surveillance would be performed during the summer over the offshore and onshore pipeline routes. In the winter holes will be drilled through the ice over the pipeline to search for leaks (U.S. Army Corps of Engineers, 1999:ES-74). However, if holes are drilled the SPCO will require the construction of protective ice berms to prevent strudel scour.

If pipelines are used in the development of the sale area, operators would follow the appropriate American Petroleum Institute recommended practices. They would inspect the pipelines regularly to determine if any damage was occurring and would also perform regular maintenance. Preventive maintenance includes installing improved cathodic protection, using corrosion inhibitors and continuing regular visual inspections.

b. Marine Terminals

The fixed location of loading facilities at marine terminals improves oil spill response and contingency planning. If a leak occurs, the facility can be rapidly shut down and the spill contained. Spill prevention measures include extensive inspection programs, monitoring of transfer operations, use of proper valves, overfill alarms, construction of secondary and tertiary containment systems around the tanks, facility security programs, training, and drug and alcohol testing of personnel. More detailed information regarding these programs are included in the oil discharge prevention and contingency plans for Alyeska's Valdez terminal.

c. Tanker Vessels

Tankers are the most cost effective and the only feasible method for transporting crude oil from Alaska to destinations in the Pacific Rim. Federal legislation through OPA 90 requires the phase-out of single-hulled tankers in favor of double-hulled tankers by the year 2010. Double-bottomed tankers, where at least 30 percent of the area beneath the cargo tank length has two bottoms, are an approved interim measure.

Several of the tankers transiting Prince William Sound are double-hulled, and OPA 90 requires tankers in Prince William Sound to be accompanied by two escort vessels to Hinchinbrook Entrance. Escort tugs are to keep tanker vessels off the rocks should the tanker lose power. Alyeska Pipeline Company's spill response organization, SERVUS, maintains five escort response vessels and four tug escort vessels for this purpose. As a result of a recent risk assessment, a high-power escort tug will be stationed at Hinchinbrook (Lisiechki, 1997). See the discussion on Oil Spill History and Risk for additional details regarding risk-reduction actions in Prince William Sound.

Many carriers voluntarily follow various other practices that also reduce the risk of oil spills. These practices may include having two licensed officers or one licensed officer and one licensed marine pilot on deck at all times, keeping anchors ready for emergency use when traversing high risk areas, plotting fixes frequently, conducting unscheduled anchoring drills in the lower inlet, performing regular maintenance procedures and special inspections in preparation for the winter climate, and incorporating special adaptations for tanker use in severe winter conditions.

All tanker crews participate in spill prevention and response training and substance abuse testing. The oil discharge prevention and contingency plans for Prince William Sound vessel operations contain more detailed information regarding spill prevention programs.

4. Oil Spill Response

The Responsible Party (RP) is responsible for preventing and responding to oil spills. Alaskan oil industry operators have found it more efficient and cost-effective to form oil spill response cooperatives to coordinate these efforts.

Alaska Clean Seas (ACS) is an oil industry sponsored, not-for-profit organization that provides the oil spill response function in support of petroleum-related activities on the North Slope and in the coastal and OCS waters off the coast of the North Slope of Alaska. The organization was originally established in Prudhoe Bay in 1979 under the name of ABSORB (Alaskan Beaufort Sea Oilspill Response Body) to support offshore exploration ventures in the Alaskan Beaufort Sea. In 1990 ACS owner companies expanded the mission to include response operations both offshore and onshore. The organization's objectives are to:

- Provide manpower and management to conduct oil spill response operations both offshore and onshore;
- Develop spill response technology for the area;
- Acquire an appropriate inventory of the best available countermeasure equipment and materials;
- Maintain the equipment and material in a high state of readiness; and
- Provide spill response training for personnel of member companies and their contractors.

The operating area includes the North Slope and the Alyeska Pipeline corridor north of the crest of the Brooks Range and Beaufort Sea coastal and OCS waters. The US Coast Guard has certified ACS as a Class E Oil Spill Response Organization in nearshore and river environments. This is the highest certification available. ACS provides manpower and equipment resources from its main base in Deadhorse and from within each of the operating oilfield units to assist in spill containment and recovery (Dickins & Glover, 1996).

North Slope operating companies coordinate with ACS to ensure a pool of trained manpower is available for an extended response. Under the current (1995) agreement to consolidate spill response resources, approximately 115 trained employees and contractors are available per shift from the various operating areas on the North Slope for immediate response in the event of a spill incident. All on-shift members of the North Slope Spill Response Team (NSSRT) are available for call-out through dedicated paging systems within each of the units. ACS also manages existing contracts with several spill response and service contractors to provide additional people with hours from their initial call-out. Contracted response services include aviation support, telecommunications services, veterinary services, computerized mapping, catering and security (Dickins & Glover, 1996).

ACS has purchased and maintains a spill response equipment inventory valued in excess of \$20 million at this time. This equipment is designed to respond to spills within the defined area of operations, under all environmental conditions. The ACS members have built corresponding inventories capable of meeting the immediate response needs of their respective units. The 1996 North Slope Operators Mutual Aid Agreement for Spill Response enables each of the operating member companies, BPX, ARCO Alaska, Inc. (ARCO) and Alyeska Pipeline Service Company (APSC), to share equipment resources in the event of a significant spill within any of the North Slope operating units. To assist with this task, ACS manages the combined inventory of all dedicated North Slope spill response assets in a single, computerized maintenance and job order system (Dickins & Glover, 1996).

Within the state of Alaska there are other spill response organizations, each with their respective areas of operation and commitment. Cook Inlet Spill Prevention and Response, Inc. (CISPRI) in the Cook Inlet and SERVS in Prince William Sound are two of the major Alaskan organizations with which ACS has developed close working relationships to facilitate immediate support of a major spill response effort anywhere within Alaska. Should it become necessary, ACS can request additional equipment from these other cooperatives and industry sources (Dickins & Glover, 1996).

ACS personnel are on call seven days a week, 24 hours a day while they are on-shift. The time necessary to arrive at a spill site with the appropriate equipment depends on a number of variables. As a general guide, immediate response to small spills in the nearshore area of the Beaufort Sea will be available

within the first few hours using pre-staged response resources and personnel from within the responsible party's unit. With offshore boom, vessels and skimmer systems pre-staged at West Dock, an offshore first-response task force consisting of ACS personnel and equipment could be on site in the vicinity of Prudhoe Bay within hours of notification, depending on weather conditions. In the event of a catastrophic spill requiring full mobilization of North Slope resources, oil spill response barges would be equipped and placed into service to assist with containment, recovery, transfer and lightering operations (Dickins & Glover, 1996).

Immediate spill response requirements are met through the use of Spill Response Teams (SRTs) comprised of company and contractor employees at each of the fields who voluntarily enlist in their particular field's SRT. The SRTs are integrated into the North Slope Spill Response Team (NSRT), comprised of 115 field responders per shift, each of which has or will receive 40 hours of hazardous materials (HAZWOPER) training. The North Slope operators who furnish the SRTs from their employee and contractor staffs have committed to make the SRTs available on a Slope-wide basis for up to 36 hours upon call-out (ACS, 1995:3).

ACS and the North Slope operators employ a "tiered system" for responding to spills. Small, non-emergency spills are cleaned up by the Operator or ACS personnel. Spills requiring the resources of ACS and the responsible party's SRT are considered Level I spills. Depending on activity levels and the duration of work to do, off-site contractor-supplied personnel may be used to complete the cleanup and may be obtained through one or more of the master agreements which ACS maintains with labor contractors (ACS, 1995:3).

If a spill requires more than the resources of ACS and the responsible party (RP), it is considered to be a Level II spill. Additional manpower resources would be obtained through mutual aid. Mutual aid is a system that utilizes SRTs from companies other than that of the responsible party. Such spills usually require some longer term cleanup. Under its master service agreements, ACS can obtain 100 contract responders within 36 hours (ACS, 1995:3).

If a spill exceeds the resources available on the North Slope, it is classified as a Level III spill. These types of spills will not only receive initial response from the full North Slope Response Team (NSRT), but will likewise require the work of off-site contract responders under ACS's master service agreements (ACS, 1995:3).

ACS established a central Incident Command Post at Deadhorse as a control point for oil spill response radio and telephone systems for the entire North Slope area. Coverage extends north from 68 degrees latitude (approximately Cape Seppings on the Chukchi Sea) and east to the Canadian border, including a range of several hundred miles offshore in the Chukchi Sea. This radio and telephone communications system is capable of being rapidly deployed by sea, land, or air to local and remote areas in support of offshore exploration or oil spill response actions. Remote control circuits for nine permanent Very High Frequency (VHF) repeaters and marine coast stations, installed at strategic locations in the production area and pipeline corridor, are routed via private microwave circuits into the system. Other High Frequency (HF) and Ultra High Frequency (UHF) radios are also connected to the system. Communication is then possible among all users, whether marine-based radios, company headquarters or supply depots, ICP, hand held portable radios, or aircraft radios. This gives each member company access to all of the radio systems, regardless of the type of radio it is using. ACS also has mobile VHF radios and hand held radios for field use in its oil spill response program (ACS 1991, Vol. 1, No. 2:3), (ACS 1991 Deadhorse Spill Response Telecommunication Center).

Other operational equipment includes four INMARSAT satellite telephone systems, operating independently of wires and separate from the VHF, UHF, and other radio systems, at Deadhorse on the North Slope. The name INMARSAT is derived from "international, marine, satellite." The system can reach anywhere in the world via satellite. An INMARSAT system can be mounted on a boat, in such a way that, regardless of heavy seas or other disturbance, the antenna beam cannot be shaken off the satellite and communication disconnected. Ships, barges, aircraft, oil spill response agencies, ground personnel, and anyone with a telephone can be reached via this system. The equipment is operational now and can be used immediately in case of an emergency anywhere in the state (Wheeler, personal communication, 1991).

ACS trains North Slope village teams to support oil spill response capability. Intensive training courses for village team members include winter and summer oil spill operations, hazardous waste operations,

oil spill post-emergency response, oil spill assessment, tracking and detection of oil, skimmer operations, incident command, and basic radio voice procedures. The teams take part in field exercises and the annual North Slope mutual aid response exercises. Village members have been asked to provide training for other team members in survival techniques in the arctic, small boat operation techniques in arctic waters, and environmental concerns, because of their unique knowledge of the arctic environment (ACS 1991, Vol. 1, No. 1:2-8).

ACS developed a wildlife protection strategy in cooperation with federal and state government agencies. The strategy utilized guidelines taken from the Wildlife Guidelines for Alaska in the Alaska Region Oil and Hazardous Substances Pollution Contingency Plan produced by the Regional Response Team. Three areas of concern were identified: 1) controlling spilled oil at the source to prevent or reduce contamination of species or their habitat; 2) keeping wildlife away from oiled areas through deterrent techniques; and 3) capturing and treating of oiled wildlife. Training courses are being developed to ensure that the hazing, capture, and stabilization are conducted safely for both the wildlife and the personnel involved (ACS 1991, Vol. 1, No. 3:1).

The Alaska Regional Response Team (ARRT) signed a Memorandum of Agreement in February 1991 pre-approving in situ burning as a spill response technique for certain ACS areas of responsibility. Pre-approval vests the final decision with the Federal On-Scene Coordinator (U. S. Coast Guard offshore; EPA or BLM onshore) and facilitates quick decision-making (ACS 1991, Vol. 1, No. 1:5).

In 1997-98 the Industry/Agency North Slope Spill Response Project Team worked together to review the studies that had been done regarding Arctic oil spill response and to assist ACS in preparing a technical manual for spill response on the North Slope and Beaufort Sea. The manual has been finalized and approved. The manual and the background documents supporting it are a compilation of the latest research and best available technology regarding oil spill response in the Arctic. The response tactics in the manual are designed to be used as building blocks for operators to prepare facility-specific response scenarios in their oil discharge prevention and contingency plans. The manual describes key response planning parameters for a variety of climatic and environmental conditions that may be encountered. It was intended to provide direction and consistency in developing generic scenarios for a variety of receiving environments. The purpose of the entire project is to increase the level of industry preparedness to meet oil spills of various kinds under a variety of conditions (ACS, April 1999). The manual consists of three volumes: Tactics Descriptions, Map Atlas, and North Slope Incident Management System and will augment the C-plans that each operator must prepare prior to beginning operations. The manual represents a major advance in the organization and coordination of spill response planning and preparedness on the North Slope. The reader is referred to the Technical Manual for a thorough description of response activities.

Alaska Clean Seas is participating in the research program, MORICE (Mechanical Oil Recovery in Ice Infested Waters). The program, which began in 1995, is a multinational effort to develop technologies for more effective recovery of oil spills in ice-infested waters. Phase 1 involved an extensive literature review to identify available information from previous efforts to develop oil-in-ice recovery technologies. Phase 2 focused on qualitative laboratory testing of most of the concepts suggested in Phase 1. Phase 3 will further evaluate and develop selected concepts through quantitative laboratory testing.

The Alaska Regional Response Team (ARRT) established by OPA 90 monitors the actions of the Responsible Party. The Team is composed of representatives from 15 federal agencies and one representative agency from the state. The ARRT is co-chaired by the U.S. Coast Guard and Environmental Protection Agency. ADEC represents the state of Alaska on the Team. The team provides coordinated federal and state response policies to guide the Federal On-Scene Coordinator in responding effectively to spill incidents. The ARRT has developed guidelines regarding wildlife, in situ burning, the use of dispersants, and the protection of cultural resources, which include archaeological and historic sites (ADEC, 1994).

All spill response organizations use the Incident Command System (ICS) to manage their response activities. The ICS system is designed to organize and manage responses to incidents involving a number of interested parties in a variety of activities. Since oil spills usually involve multiple jurisdictions, the joint federal/state response contingency plan incorporates a unified command structure in the oil and hazardous

substance discharge ICS. The unified command usually consists of the Federal On-Scene Coordinator, the State On-Scene Coordinator, the Local On-Scene Coordinator and the Responsible Party On-Scene Coordinator. Industry and agency personnel in the operations, logistics, planning and finance sections of the incident command system gather information and make recommendations on response and cleanup objectives and strategies to the unified command (ADEC, 1994).

The Unified Command jointly makes decisions on objectives and response strategies. However, only one Incident Commander is in charge of the spill response. The Incident Commander is responsible for implementing these objectives and response strategies (AS 46.04.200(b)(2) and (3)). The Responsible Party's Incident Commander may remain in charge until or unless the Federal On-Scene Coordinator and the State On-Scene Coordinator decide that the Responsible Party is not doing an adequate job of response (ADEC, 1994).

Ice conditions, in ever-changing stages of development and degradation, are present for over 280 days out of every calendar year in the Beaufort Sea nearshore environment. Additionally, wind driven ice invasions during the open water season, typically July through September, may also occur for periods of seven to ten days, each with ice-to-water concentrations of 2:10 to 4:10. This presence combined with extreme arctic conditions routinely presents a challenge to mounting a safe and effective oil spill response action. To overcome this challenge responders must develop response action plans with an understanding of the physical environment of the response operations area and an understanding of the effect this environment will have on the fate and behavior of the spilled oil. Arctic spill response strategies, worldwide, have been developed through twenty years of experience with both offshore and onshore drilling and production operations in all types of sea and ice conditions. Alaska Clean Seas (ACS) has based its North Slope response action plans on this experience, intense field training, and investigation and ground-truthing of related research and development projects (Dikins & Glover, 1996).

Many oil spill response research and development projects have studied oil and ice interactions over the last 20 years. Beginning with the research conducted offshore in the Canadian Beaufort Sea and followed by projects in the Alaskan and Norwegian Arctic, scientists and responders have studied oil behavior, developed and tested methods and tools to mitigate the effects of an oilspill in, on or under ice. Arctic spill research projects have explored, under various ice conditions, aspects including oil weathering characteristics, spreading under ice, encapsulation and migration, remote sensing, trajectory modeling, and the testing of in situ burning, dispersants, and conventional containment and recovery equipment (Dikins & Glover, 1996).

During the development of the ACS Technical Manual, the project team commissioned a re-evaluation of the capability of cleaning up spilled oil from large blowouts in broken ice conditions. Current state regulations require that operators be able to mechanically entrain and recover, within 72 hours, a response planning standard (RPS) volume of oil. For exploration and production facilities, the RPS from an uncontrolled blowout is a minimum of 5,500 barrels per day. If well data indicate a higher production rate, the RPS is adjusted accordingly. The industry can meet the RPS in open water and solid ice conditions; however, broken ice conditions present special problems. Conventional booms and skimmers have difficulty working efficiently among the broken ice. The analysis indicates that mechanical methods cannot recover sufficient quantities of spilled oil to meet the state's required 72-hour RPS standard in broken ice conditions (S. L. Ross Environmental Research Ltd., 1998).

5. Cleanup and Remediation

Cleanup plans for terrestrial and wetlands spills must balance the objectives of maximizing recovery while minimizing ecological damage. Many past cleanup operations have caused as much or more damage than the oil itself. All oils are not the same, and knowledge of the chemistry, toxicity and destination of the spilled oil can help identify those cleanup techniques that can reduce the ecological impacts of an oil spill. Hundreds of laboratory and field experiments have investigated the destination, uptake, toxicity, behavioral responses, and population and community responses to crude oil. (Jorgenson, 1996)

The best techniques are those that quickly remove volatile aromatic hydrocarbons. This is the portion of oil that causes the most concern regarding the physical fouling of birds and mammals. To limit the most

serious effects, it is desirable to remove the maximum amount of oil as soon as possible after a spill. The objective is to promote ecological recovery and not allow the ecological effects of cleanup to exceed those caused by the spill itself. Table 6.2 lists cleanup objectives and techniques that may be applicable to each objective. Table 6.3 compares the advantages and disadvantages of cleanup techniques for crude oil in terrestrial and wetland ecosystems (Jorgenson, 1996).

Table 6.2 Objectives and Techniques for Cleaning Up Crude Oil in Terrestrial and Wetland Ecosystems (Adapted from Jorgenson, 1996)

Objectives	Cleanup Techniques
Minimize:	
Movement of oil	Absorbent booms Sand bagging Sheet piling
Surface-water contamination	Same as above
Soil infiltration	Flood surface
Soil and vegetation contact and oil adhesion	Flood surface Use surfactants to reduce adhesion
Vegetation damage	Use boardwalks to reduce trampling Use flushing instead of mechanical techniques Perform work when vegetation is dormant
Thawing of Permafrost	Avoid vegetation and surface disturbance
Wildlife contact with oil	Fencing to prevent wildlife from entering site Plastic sheeting to prevent birds from landing on site Guards to haze wildlife Devices to haze wildlife
Acute and chronic toxicity of oil to humans, fish, and wildlife	Removal of oil Enhance biodegradation of remaining oil
Waste disposal	Use flushing Avoid absorbents and swabbing
Cost	Remove oil as fast as possible Achieve acceptable cleanup level quickly to minimize monitoring
Liability	Achieve acceptable cleanup level
Maximize:	
Recovery potential of tundra ecosystems	All of the above Add nutrients to aid recovery of plants
Worker safety	Air testing, training, clothing

Table 6.3 Advantages and Disadvantages of Techniques for Cleaning Up Crude Oil in Terrestrial and Wetland Ecosystems (Adapted from Jorgenson, 1996)

Technique	Advantage	Disadvantage	Recommended
Wildlife:			
Fencing	Keeps out large mammals	Does not keep out birds	Yes
Plastic sheeting	Keeps out both birds and mammals	Can no longer work area	Sometimes
Wildlife guard	Flexibility to respond	Higher cost	Sometimes
Devices	Lower cost	Animals become habituated	No
Containment:			
Absorbent booms	Contains floating oil, quickly deployed	Misses water soluble oil	Yes
Sand bags	Contains both floating and soluble fractions, follows tundra contours	Slower to mobilize, some leakage	Yes
Sheet piling	Maximum containment	Slow to install, doesn't fit contours well	Sometimes
Earthen berms	Can easily be adapted to terrain, heavy equipment rapidly can create berms	Destroys existing vegetation and soil	No
Snow/ice berms	Can be used during winter cleanup or to prevent runoff during breakup	Can only be used during freezing periods	Yes
Contact:			
Flooding	Keeps heavy oil suspended	Spreads out oil	Yes
Surfactants	Reduces stickiness, aids removal, and reduces volatilization	Reduces effectiveness of rope mop skimmer	Yes
Thickening agents	Untried, aids physical removal	Must be well drained, physical removal more difficult	No
Access:			
Boardwalks	Reduces trampling	None	Yes
Removal:			
Complete excavation	Eliminates long-term liability	Eliminates natural recovery, disposal costs	Sometimes
Partial excavation	Quickly reduces oil levels, less waste to dispose of than complete excavation	Causes partial ecological damage, disposal costs, still long-term liability	Sometimes
Burning	Low cost, high removal rate	Little testing, ecological damage	Sometimes
Flushing, high pressure	High removal rate	High ecological damage	No
Flushing, low pressure, cold	Moderate removal rate, little damage, easy waste disposal	Spreads oil, not as effective as warm water	No
Flushing, low pressure, warm	High removal rate, little vegetation damage, easy disposal of waste	Spreads oil	Yes
Aeration	Accelerates volatilization	Volatiles lost to air, may pose risk to humans	Yes
Raking	Can target hot spots	Partial vegetation damage	Sometimes
Cutting and trimming	Targets hot spots, reduces stickiness	Partial vegetation damage	Sometimes

Technique	Advantage	Disadvantage	Recommended
Swabbing	Targets hot spots	Not very effective, adds to waste disposal, adds to trampling	No
Oil skimmers and rope mops	Removes heavier oil, works well with flooding, lowers disposal costs	Requires personnel to push oil to skimmer, adds to trampling	Yes
Vacuum pumping	Removes surface and miscible oil, works well with flooding, lowers disposal cost	None	Yes
Biodegradation	Removes low levels of hydrocarbons, non- destructive, lowers disposal costs	Long-term monitoring, site maintenance, may require wildlife protection	Yes

After a spill, the physical and chemical properties of the individual constituents in the oil begin to be altered by the physical, chemical, and biological characteristics of the environment. This is called weathering. As much as 40 percent of most crude oils may evaporate within a week after a spill. The factors that are most important during the initial stages of cleanup are the evaporation, solubility and movement of the spilled oil. Over the long term, microscopic organisms (bacteria and fungi) break down oil (Jorgenson, 1996).

Cleanup phases include initial response, remediation and restoration. During initial response, the spiller gains control of the source of the spilling oil; contains the spilled oil; protects the natural and cultural resource; removes, stores and disposes of collected oil; and assesses the condition of the impacted areas. During remediation, the responsible party performs site and risk assessments; develops a remediation plan; and removes, stores and disposes of more collected oil. Restoration attempts to re-establish the ecological conditions that preceded the spill. The restoration phase usually includes a monitoring program to access the results of the restoration activities (Jorgenson, 1996).

Mitigation Measures

Recognition of the difficulties of containment and clean up of oil spills in the Arctic has encouraged innovative and effective methods of preventing possible problems and handling them if they arise. Oil spill prevention, response, and cleanup and remediation techniques are continually being researched by state and federal agencies and the oil industry. Although the risk of impact from a spill cannot be reduced to zero, such risk can be minimized through preventative measures, monitoring, and rigorous response capability. In addition to addressing the prevention, detection, and cleanup of releases of oil, Lessee Advisory 7 alerts possible lessees that they must develop an approved C-plan before they may begin operations. Among many other requirements, C-plans must identify the location of oil spill cleanup equipment; the location and availability of suitable alternative drilling equipment; and develop a plan of operations to mobilize and drill a relief well.

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